U.S. Department
of Transportation

Research and
Special Programs
Administration

OPA 90
Programmatic Regulatory Assessment (PRA)

TECHNICAL APPENDICES

May 2001

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Prepared for:
U.S. Coast Guard
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Washington, DC

Acronyms

ACOE	U.S. Army Corps of Engineers
BNSR	Barrels of oil not spilled or spilled and removed from the water
CFR	Code of Federal Regulations
COR	Certificates of Registry
COTP	Captain of the Port
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DSC	Deck Spill Control
EEZ	Exclusive Economic Zone
E&P	Equipment and Personnel
ERV	Escort Response Vessel
FBI	Federal Bureau of Investigation
FR	*Federal Register*
GNP	Gross National Product
GT	Gross Tonnage
IMO	International Maritime Organization
MMD	Merchant Mariners' Documents
MODU	Mobile Offshore Drilling Unit
MSIS	Marine Safety Information System
MTR	Marine Transportation Related
NPFC	National Pollution Funds Center
NRC	National Research Council
NRDA	Natural Resource Damage Assessment
OMB	Office of Management and Budget
OPA 90	Oil Pollution Act of 1990
PNS	*Port Needs Study* (USCG, 1991)
PRA	Programmatic Regulatory Assessment
PRAAM	Programmatic Regulatory Assessment Accounting Model
PWS	Prince William Sound (Alaska)
RA	Regulatory Assessment
SCC	Spill Source Control and Containment
TAPS	TransAlaska Pipeline System
TPV	Total Present Value
USCG	United States Coast Guard
VRP	Vessel Response Plan

CONTENTS

TABLES

A. OPA 90 RULES

Table A-1
OPA 90 Rules

Docket Number	OPA 90 Section	Title of Rule
90-051	4115 (a)	Establishment of Double Hull Requirements for Tank Vessels
90-052	4115 (d)	Requirements for Cargo Lightering Operations
90-068 DSC	4202 (a)	Discharge Removal Equipment and Inspection, Vessels Carrying Oil—Deck Spill Control
90-068 SCC	4202 (a)	Discharge Removal Equipment and Inspection, Vessels Carrying Oil—Spill Source Control and Containment
90-071a	4110 (b)(1)	Overfill Devices
90-071	4110 (b)(2)	Tank Level or Pressure Monitoring Devices
91-005	4303	Financial Responsibility for Water Pollution Civil Penalties (Vessels)
91-032	5004 (1)	Prince William Sound ADS System; Equipment Carriage Requirement
91-034 VRP	4202 (a), (b)	Tank Vessel Response Plans (Oil)
91-034 E&P	5005	Equipment and Personnel Requirements (PWS/TAPS)
91-036	4202 (b)(4)	Facility Response Plans (Oil)
91-045 L	4115 (b)	Emergency Lightering Equipment and Advance Notice of Arrival Requirements for Existing Tank Vessels Without Double Hulls
91-045 O	4115 (b)	Operational Measures to Reduce Oil Spills from Existing Tank Vessels without Double Hulls
91-045 S	4115 (b)	Structural Measures for Existing Single-Hull Tank Vessels
91-046	4118	Vessel Communication Equipment Regulation
91-202	4116 (c)	Escorts for Certain Tankers (Prince William Sound and Puget Sound)
91-202a	4116 (c)	Escort Requirements for Vessels on the Navigable Waters of the United States
91-203	4114 (a)	Tank Vessel Manning: Unattended Engine Rooms
91-204	4114 (a)	Tank Vessel Manning: Auto Pilot
91-209	4109	Requirements for Longitudinal Strength, Plating Thickness and Periodic Gauging For Certain Tank Vessels

Table A-1 (continued)
OPA 90 Rules

Docket Number	OPA 90 Section	Title of Rule
91-211	4102 (b), (c), (d)	Renewal of Certificates of Registry, Renewal of Merchant Mariners' Documents, Termination of Existing Licenses, Certificates, and Documents
91-212	4102 (e), 4105 (a), (b), (c)	Criminal Record Reviews in Renewals of Licenses and Certificates of Registry; Access to National Driver Register
91-216	4106 (b)	Reporting Marine Casualties
91-218	4116 (a)	Prince William Sound Pilotage
91-222	4116 (b)	Second Licensed Officer on the Bridge
91-223	4101 (b)	Review of Alcohol and Drug Abuse in Issuing Licenses and Certificates of Registry; Review of Alcohol and Drug Abuse in Issuing Merchant Mariners' Documents
91-225	4201	Delegations of Authority Under the Federal Water Pollution Control Act As Amended by OPA 90
91-228	4301 (b)	Federal Water Pollution Control Act Penalties
91-235	4202 (a)	National Planning and Response System (Hazardous Substances): Facility Response Plans
91-236	4202 (a)	National Planning and Response System (Hazardous Substances): Tank Vessel Response Plans
92-007	4302	Penalty Provisions
93-081	4115 (a)	Designation of Lightering Zones
94-101	4103 (c)	Suspension and Revocation of Licenses, Certificates of Registry, and Merchant Mariners' Documents

B. Core Group Rules and their Descriptions

Rule I: Double Hulls (90-051)

The rule requires, with certain exceptions, that all tank vessels operating in waters subject to the jurisdiction of the U.S, including the EEZ, be equipped with a double hull.

Rule II: Deck Spill Control (90-068 DSC)

The DSC rule addresses the retention and removal of small cargo spills on deck. An on-deck spill is a discharge of oil onto the deck during loading, unloading, transfer, or other shipboard operation. An on-deck spill could result from a leaking fitting, an overfill, a bad connection, or similar operational mishap. The phrase "on-deck" is used to differentiate operational discharges from discharges caused, e.g., by a collision or structural failure that results in a tank rupturing. The rule requires deck coamings,[1] portable pumps, sorbents, cleaning equipment, and waste oil disposal. Vessels are required to carry equipment that meets three criteria: it must be appropriate, must be the best technology economically feasible, and must be compatible with safe operation of the vessel.

Rule III: Spill Source Control and Containment (90-068 SCC)

The SCC rule addresses spills that do not occur on deck by means of several requirements—

- All oil tankers are required to install an emergency towing bridle (as identified in IMO Resolution A.535(13)). All oil barges must carry an emergency towing cable to be used in the event that the primary cable (that is carried as industry standard) fails. The requirement is intended to require that these barges, whether manned or unmanned, have a suitable cable for use in an emergency so that the towing vessel can maintain or regain control of the barges.

- All tankers and oil barges must possess internal and external cargo transfer capability; this includes carrying hoses and reducers, unless the vessel's existing cargo piping system is already designed to facilitate cargo transfer. The vessel's crew would move oil from a breached tank to a non-breached tank on the same vessel or to the tanks of another vessel alongside.

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[1] A coaming is a raised frame "...at least 4 inches high enclosing the immediate area of the cargo hatches, loading manifolds, and transfer connections that has a capacity, in all conditions of vessel listing...to be encountered during the loading operation, of at least one-half barrel per hatch, manifold, and connection within the enclosed area." (33 CFR 155.310).

- All owners and operators of all oil tankers and offshore oil barges must prearrange to have access to a computerized system for calculating "damage stability" information since such information will maximize the chances of salvage in the event of a casualty. In a damaged and weakened condition a vessel may pose difficult problems to a salvager who must know the vessel's stability and remaining girder strength before attempting a salvage.

Rule IV: Lightering of Single Hull Vessels (91-045 L)

This rule requires the owners and operators of single-hull oil tankers and barges operating in U.S. waters to carry certain emergency lightering equipment onboard. Lightering means the transfer of a cargo of oil from one vessel to another, including all phases of the operation from the beginning of the mooring operation to the departure of the service vessel from the vessel to be lightered. The equipment must be protected from the weather and must be stored in one separate and marked location that is as convenient to the cargo manifold as possible. Such onboard equipment is intended to facilitate rapid transfer of oil from a vessel in the event of a collision or grounding. Reducers, adapters, bolts, washers, nuts, and gaskets must allow at least two simultaneous transfer connections to be made from the vessel's cargo manifold to 6-inch, 8-inch, and 10-inch cargo hoses. One extra set of equipment per reducer must be carried as spares.

If oil cargo is improperly lightered from a vessel or if oil is lightered from the wrong tanks, additional damage to the vessel could occur, crew safety could be jeopardized, and additional oil could be discharged into the marine environment. Thus, lightering operations should not begin until salvage experts and the vessel's master have assessed the condition of the vessel. Under some circumstances, however, immediate action may be required. Even if lightering is not initiated until after a full assessment of its suitability, having the required lightering equipment onboard ensures that lightering will not be delayed.

The rule also requires foreign-flag vessel owners or operators to provide the vessels' IMO numbers before arriving at a port or place in the U.S. The purpose of the rule is to reduce damage to the environment by facilitating response and salvage efforts for a vessel in the case of a collision or grounding.

Rule V: Overfill Devices (90-071a)

This rule establishes minimum standards for overfill devices and requires the installation of one overfill device that is permanently installed on each cargo tank of a vessel. The purpose of the rule is to reduce the likelihood of spills when too much oil is pumped into a cargo tank during a transfer operation (e.g., from a facility to an oil tanker or tank barge or from one oil tanker or tank barge to another). Human error is the most-often reported cause of this type of error. Many spills are small; however, some reported spills have involved large quantities.

The overfill device must have an automated system that shuts down transfer of oil before it overflows from the tank. The device must include an independent audible alarm or visible indicator for each tank.

Rule VI: Operational Measures of Single Hull Vessels (91-045 O)

This rule requires owners or operators of oil tankers and tank barges that carry oil in bulk as cargo and that are single hull to comply with a number of operational measures. The rule contains eight operational measures—

1) **Emergency Lightering Requirements.** Amends 91-045 L (Rule IV above) to prohibit the use of cast iron and malleable iron valves and flanges that have high fatigue susceptibility.

2) **Enhanced Vessel Survey Requirements during Dry-Docking and Vital Systems Surveys.** Attempts to reduce the risk of structural failure and confirm hull integrity through an enhanced dry-dock visual inspection and specific hull plate gauging. Vital systems surveys attempt to lower the risk of equipment failure or risk of a fire.

3) **Auto Pilot Alarm.** For all oil tankers, an onboard alarm sounds when the helm is turned while autopilot is engaged.

4) **Maneuvering Performance Capability.** Requires both foreign and domestic oil tankers to conduct maneuvering capability tests to highlight those vessels with poor control capabilities. This information will provide pilots and others with critical information.

5) **Maneuvering and Vessel Status Information.** All oil tankers are required to a) have maneuvering information in a standardized format to ensure that the pilot can quickly assess the maneuvering characteristics of the vessel; b) use a pilot "card" that provides a "snapshot" of the vessel's current equipment status and maneuvering information unique to that transit; c) have a maneuvering booklet for the master of the vessel that gives detailed information on the specific maneuvering capabilities at various drafts and in various hydrodynamic situations.

6) **Minimum Under-Keel Clearance.** Attempts to lower the risk of groundings by requiring minimum under-keel clearance guidance, with under-keel clearance to be determined for each port entry.

7) **Emergency Steering.** Requires a vessel towing an oil tank barge to have either twin (propeller) screws with independent power or an emergency steering capability. This requirement applies only to vessels towing tank barges, since other Federal (non-OPA 90) regulations already apply to tankers.

8) **Fendering Systems.** Attempts to reduce structural fractures due to the stress on these tank barge hull areas where a towing vessel or pier routinely comes in contact with the barge.

Rule VII: Licenses, Certificates, and Mariners' Documents (91-211, 91-212, 91-223, and 94-101)

For the purposes of this analysis, these rules are clustered together into a single rule. This rule cluster does the following.

- Requires the renewal of Merchant Mariners' Documents (MMDs) and Certificates of Registry (CORs) once every 5 years.[2]

- Requires the Coast Guard to conduct criminal record reviews on any individual applying or reapplying for a license, MMD, or COR. Such a review will include information from the National Driver Registry relating to operation of a motor vehicle under the influence of alcohol or a controlled substance and any traffic violation arising in connection with a fatal accident or reckless driving. Applicants must be fingerprinted. A criminal record check is conducted through FBI data systems and other sources. The Coast Guard is now authorized to reject applicants if the criminal record check, or other information, indicates that an applicant's habits of life and character are such that the applicant cannot be entrusted with the duties and responsibilities associated with a license or MMD.

- Requires all applicants applying for (or renewing) a license, MMD, or COR to be tested for the use of dangerous drugs.

- Requires the suspension and revocation of licenses, MMDs, and CORs for alcohol or drug abuse (Coast Guard merged this part of the rule cluster with another rulemaking).

Rule VIII: Financial Responsibility (91-005)

This rule has the potential to expose owners and operators of vessels to greater liabilities for the removal costs and damages from oil spills than was the case with pre-OPA 90 statutes. The rule is applicable to "...vessels of any size...transshipping or lightering oil."[3] Such vessels would be

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[2] The U.S. Coast Guard issues licenses to qualified officers such as masters, mates, pilots, engineers, operators, and radio officers. MMDs authorize individuals to work in different capacities on deck and in the engine and steward's departments; MMDs with an appropriate endorsement are also the credentials issued to qualified tankermen. CORs are issued to officers in positions such as medical doctor or nurse.

[3] This means "...both delivering and receiving vessels." Rule VIII considers Mobile Offshore Drilling Units, (MODUs—vessels capable of use as offshore facilities) as vessels. (*FR*, 7/1/94, pp. 34213 and 34216).

prohibited from operating in waters within which the U.S. has jurisdiction, unless the operators demonstrated beforehand some form of financial assurance sufficient to meet their potential liability under OPA 90 for an oil spill. The rule encourages needed resources to be made available for immediate clean up of a spill to reduce the adverse consequences from the spill due to winds, tides, currents, and other factors. Moreover, to the extent that owners and operators demonstrate financial responsibility through insurance, substandard vessels and inferior vessel operations are expected to occur less often as a result of increased safety vigilance by vessel operators and insurers.

Rule IX: Vessel Response Plans (91-034 VRP)

This rule requires all owners and operators of oil tankers and tank barges to prepare and submit to the Coast Guard a vessel plan for responding, to the maximum extent practical, to a worst case discharge of oil and to the substantial threat of such a discharge.[4] Vessel Response Plans (VRPs) reduce marine pollution in three ways—

1) By reducing the likelihood of an oil spill, given that a vessel accident has occurred

2) By reducing the volume of oil spilled into the environment, given that a spill has occurred

3) Strengthening the actual management of the spill response/removal effort

Rule X: Facility Response Plans (91-036)

This rule requires all owners and operators of certain facilities to prepare and submit to the Coast Guard individual facility response plans. The applicable facilities are all marine transportation-related offshore facilities (except pipelines) and any marine transportation-related onshore facility that because of its location could reasonably be expected to cause substantial harm to the environment by discharging oil into or on U.S. navigable waters, adjoining shorelines, or the EEZ.[5]

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[4] "Worst case discharge" means a discharge in adverse weather conditions of a vessel's entire oil cargo; "maximum extent practical" is defined as the planned capability to respond to a worst case discharge. The VRP must 1) identify the qualified individual having full authority to implement removal actions; 2) require immediate communication between that individual and the appropriate Federal official; 3) identify and ensure the availability of, by contract or other approved means, private personnel and equipment necessary to remove and to mitigate or prevent the discharge; 4) describe the training, equipment testing, periodic unannounced drills, and response actions of persons on the vessel to be carried out under the plan to mitigate or prevent a substantial threat of a discharge; 5) be updated periodically and resubmitted for approval of significant changes.

[5] "Facility" means any structure, group of structures, equipment, or device (other than a vessel) that is used for one or more of the following purposes: exploring for, producing, storing, handling, transferring, processing, or transporting

Rule XI: PWS Equipment and Personnel Requirements (91-034 E&P)

OPA 90 places unique requirements on all owners and operators of oil tankers and tank barges[6] operating in Prince William Sound (PWS), Alaska, above and beyond those that OPA 90 imposes on oil tankers and tank barges operating elsewhere in U.S. waters. Those acquisitions and activities that are a direct and exclusive result of Section 5005 of OPA 90 are as follows.

- **Prepositioned Equipment.** Requires dedicated equipment and personnel to be placed in strategic locations around PWS. Such equipment includes two large barges with liquid storage capacity, skimmers and boom, prepositioned near each of two islands in PWS, and "defensive" equipment located at designated response centers near the salmon hatcheries.[7]

- **Training.** Both local residents and individuals engaged in cultivation or production of fish or fish products must receive basic training in oil spill containment and removal techniques so that they may assist in protecting property and economic interests. Training of residents occurs in the five towns in PWS; employees of the hatcheries receive the training on site. Subjects covered are those appropriate for people participating in near-shore containment and cleanup (i.e., "defensive" operations). This training is exclusive of and different from that given to personnel employed by spill-response organizations or companies, who conduct "offensive" response operations in the vicinity of the spill.

- **Area Drills.** At least two drills must be conducted annually. These drills are announced beforehand. They are simulations of vessel spills in various locations; a few simulate spills from onshore facilities. Simulated spills must involve the actual transportation of equipment, personnel, and supplies to the simulated spill location. Where practical, both "offensive" and "defensive" equipment will be tested, including skimming, lightering, and deployment of boom.

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oil. This term includes any motor vehicle, rolling stock, or pipeline used for one or more of these purposes. "Offshore facility" means any facility of any kind located in, on, or under any of the navigable waters of the U.S., and any facility of any kind that is subject to the jurisdiction of the U.S. and is located in, on, or under any other waters, other than a vessel or public vessel. "Onshore facility" means any facility of any kind located in, on, or under any land within the U.S. other than submerged land. Several OPA 90 rules apply to any offshore facilities and certain onshore facilities.

[6] The Coast Guard has exempted all vessels that do not load at the TransAlaska Pipeline System (TAPS). Tank barges are not part of this traffic.

[7] Requirements attributable to Section 5005 and prepositioned throughout PWS consists of barges with liquid storage capacity, response vessels, skimmers, and dedicated personnel from the Alyeska Corporation. The 1992 RA for this rule estimated that the potential oil recovery capability of Alyeska's prepositioned equipment over the crucial first 3 days following a large tanker spill is 25 percent of any spill volume; however, the total practical recovery capability of oil over the same 3-day period cannot exceed 256,000 BNSR.

C. Expert Panels

Introduction

The Volpe Center project team developed a method for estimating the overall benefit of a selection of OPA 90 regulations, while giving consideration to the combined and interactive effects of these regulations. The credibility of the output of this method was dependent upon subjective judgements in two critical estimates—

1) Oil spill baselines in the future

2) Effectiveness of individual regulations on these baselines

To assist in developing these estimates, the Volpe Center assembled specialized private-sector and Federal-agency expertise into two panels—

1) Expert Panel A to address oil spill baselines

2) Expert Panel B to address effectiveness of individual regulations

The Volpe Center planned, designed, and facilitated three structured workshops to solicit expert opinions on a number of questions. Panel members were provided packages of materials to study in advance of the workshops, which included the purpose and scope of the project and panel workshops, preliminary baselines estimated by the Volpe Center, and specific questions panel members would address in the workshops. Expert opinions were captured, evaluated, and incorporated into the final estimates of benefits of selected regulations.

Individual opinions of panel members were collected while maintaining anonymity of specific panel members. Consensus on each question was not required, though adequate time for discussion, argument, and rebuttal was provided for each question.

The results of Volpe-team application of effectiveness estimates (Expert Panel B) to revised oil spill baselines (Expert Panel A) were presented to Expert Panel B in a final workshop. At this workshop, Expert Panel B was asked to evaluate the adequacy of the results for the PRA and to indicate acceptance or to offer additional recommendations.

Coast Guard's Marine Safety and Environmental Protection project team and the Volpe Center project team were responsible for the overall method of analysis, the design and objectives of the workshops, the constraints on the focus of the expert panels, and the final application of expert opinions. The responsibility of the expert panel members was limited to judgements they each articulated during the workshops in response to specific questions posed by the Volpe Center.

The panel membership brought to the workshops a broad knowledge base and extensive experience with the assigned subject matter. Although individual panel members did not claim expertise in all required areas, the panel as a whole possessed the backgrounds required. Two members served on both panels, adding experience and providing continuity.

Expert Panel A—Baseline Oil Spill Forecasts

Requirements

- Three private-sector individuals, each with at least 10 years of relevant professional experience in 1 or more of the following.
  - — Consulting/contractor/academia in marine oil transportation, oil spill prevention, spill response, environmental protection engineering, research, or planning
  - — Waterborne oil transportation systems and their spill histories, including knowledge of trends prior to and since OPA 90
  - — Past service on an NRC Marine Board Committee
- Collectively possess experience and knowledge of evolving national and world patterns of oil transportation as well as current and planned spill prevention action by industry, individual states, and foreign governments, independent of OPA 90 regulations.
- In addition to the private-sector individuals, two Federal-agency personnel with expertise in oil transportation and oil spill historical trends were included on the panel.

Members

Keith Michel	Herbert Engineering Corporation
Henry S. Marcus	Marine Systems—Ocean Engineering, MIT
David G. St. Amand	Navigistics Consulting
Barry N. Cohen	Energy Demand Analysis, DOE
Captain James M. Garrett	Quality Assurance and Inspection, USCG

Workshop Advance Information Packet

Workshop—November 18, 1996. 8:00am–5:00pm

Volpe National Transportation Systems Center, Cambridge, Massachusetts

Agenda

1) Introductions and Objectives

2) Procedures—Presentation and Discussion

   - History and forecast of oil transported in bulk by tankers and barges
   - Oil commodities transported by tankers and barges
   - Single-hull phase out
   - History of oil spills by spill source
   - Baseline forecasts of yearly spill quantities by source
   - Forecast of oil tanker traffic in PWS, Alaska
   - Baseline estimates of recovered spilled oil
   - Baseline estimated considerations

Objectives

- Expert Panel A will review, critique, and modify as needed Volpe Center forecasts of waterborne oil transportation in U.S. navigable waters and oil spills from specific source (tankers, barges, lightering operations, and facilities)
- Oil spills forecasts will serve as baseline for estimated benefits attributable to specific OPA 90 regulations

Procedures

- Presentation of forecast methodologies and results, followed by request for validation or change
- Panel discussion follows presentation of each step and its product
- Panel acceptance or recommendation for revision requested at each step
- Individual opinions of panel members will be anonymously recorded

Baseline Oil Spill Forecasts

- Benefits of OPA 90 rules will be estimated as the total life-cycle quantity of oil "not spilled" or if spilled, "recovered"
- Panel A function is to validate or suggest appropriate revision to Volpe-prepared baseline spill forecasts
- Panel B function is to estimate percentage reductions in spillage attributable to selected OPA 90 rules
- Volpe Center baseline oil spill forecast method is presented as a 6-step process—

  1) Total oil transported in bulk by tankers and barges—history and forecast
  2) Oil commodities transported by tankers and barges
  3) Single-hull phase out
  4) History of oil spills by spill source
  5) Historical spill rates by spill source
  6) Forecasts of yearly quantities of oil spillage by spill source

Total oil transported in bulk by tankers and barges—history and forecast

[Figure A-1 and Table A-1 not included in this appendix]

- ACOE *Waterborne Commerce of the United States (WCUS), Part 5 National Summaries* (1994), Table 1-5 Total Waterborne Commerce 1975–1994 by Commodity Group is the source of historical total yearly quantities of crude oil and petroleum products transported in U.S. navigable waters (33 CFR 2.05–25) and the EEZ (33 CFR 2.05–35)

- To represent the total bulk oil transport affected by OPA 90 regulations, two ACOE commodities have been deleted (petroleum coke and liquid natural gas) from the ACOE national totals for "Petroleum and Petroleum Products"

- In order to estimate future quantities to be transported, average annual rates of growth have been applied to the 1994 value (latest year available) to represent 1995–2025

- A high growth rate and a low growth rate have been applied to represent a band of the most likely future of oil transported through 2025; *The DOE Energy Information Administration's Annual Energy Outlook 1996 with Projections to 2015*, Table A-1 Total Energy Supply and Disposition Summary was used as the basis for average annual growth rates for the projections through 2025

Discussion Questions

- Do the ACOE *Waterborne Commerce* statistics adequately represent total quantity of petroleum and petroleum products transported by water during this historical period?

- Does the exclusion of petroleum coke and liquid natural gas produce an adequate representation of the shipping affected by OPA 90 rules?

- Is the range between high annual growth (1.9 percent per year) and low annual growth (0.9 percent per year) of national total oil transport between 1995 and 2025 depicted in Figure A-1 reasonable?

- What changes, if any, to this forecast would you recommend?

Oil commodities transported by tankers and barges

[Figures A-2 and A-3 and Table A-2 not included in this appendix]

- In order to provide a perspective of the petroleum commodities transported in U.S. waters, the percentage distribution of the 1993 total tons (excluding petroleum coke and liquid natural gas) is displayed on the pie chart of Figure A-2

- Figure A-3 is a bar chart showing the 1993 tons of each of the same petroleum commodities transported by tanker and barge

- The source for Figures A-2 and A-3 and Table A-2 is a database of 1993 statistics prepared for the Volpe Center by ACOE Navigation Data Center, Waterborne Commerce Statistics Center for other USCG and MARAD studies

- The 1993 traffic patterns, commodity mix, and tanker and barge shares of the total oil transport are assumed essentially unchanged through 2025

Discussion Questions

- Is it reasonable to assume that the commodity mix distribution and the tanker and barge tonnage shares of the totals will remain essentially constant through the forecast time period?

- If not, what change would you recommend?

Single-hull phase out

[Figures A-4 and A-5 and Table A-3 not included in this appendix]

- OPA 90 regulations require that single-hull vessels transporting bulk petroleum be phased out by 2015; in the interim, they are subject to specific regulations that affect only that portion of the total petroleum that is actually transported in single-hull vessels

- Figure A-4 displays the high growth rate scenario of total bulk oil transport by tankers and barges combined and an approximation of the expected phase-out of single-hull transport through 2015

- Figure A-5 displays the same information but for the low growth rate scenario

- Table A-3 shows the projected total tons of bulk transport and the estimated percent of the total transported in double hulls and single hulls each year; these yearly percentages approximate the 5-year interval percentage estimates shown in Table 3.4.6 Phase-in Schedule for Alternative Designs, *Interim Regulatory Impact Analysis for the Oil Pollution Act of 1990 Titles IV and V,* October 1991, by TBS/Mercer Management Consulting

Discussion Questions

- The interim regulatory impact analysis was completed in 1991—is this timeline for single-hull phase-out still a reasonable estimate?

- What changes, if any, to this forecast would you recommend?

History of oil spills by spill source

[Figures A-6, A-7, A-8, and A-9 not included in this appendix]

- The history of oil spills in U.S. navigable waters and EEZ is recorded in the USCG Oil and Hazardous Substance Spill Database; Dr. Robert Brulle prepared for the Volpe Center a special extract of the USCG database that serves as the source of the spill data presented in Figures A-6 through A-9
- Figure A-6 displays the total number of individual spills recorded each year from 1973–1996 by each of the four spill sources defined for the PRA (tankers underway, barges underway, lightering operations, facilities)
- Figure A-7 displays the total quantity of oil spilled each year by the same spill sources
- Figure A-8 displays the distribution of the individual spills by nine spill size categories
- Figure A-9 displays the distribution of the total quantity of spilled oil by the same nine spill size categories

Historical spill rates by spill source

[Figures A-10 and A-11 and Table A-4 not included in this appendix]

- In order to estimate oil spillage in future years through 2025 the proposed method is to apply an average spill rate for each spill source to the projected tons of oil transported each year
- Average spill rates for each spill source (tankers underway, barges underway, lightering operations, facilities) were calculated by dividing the total gallons spilled by each source over a selected time period by the appropriate tons transported over the same time period
- Three different period were examined: 1973–1980, 1973–1990, and 1981–1990
- Figure A-10 displays three historical spill rates for each spill source in terms of the number of individual spills per million tons of oil transported; Figure A-11 displays similar rates in terms of gallons spilled per million tons of oil transported
- The spill rate for the period from 1991 to date is not presented because the data for this time period are considered unreliable

Forecasts of yearly quantities of oil spillage by spill source

[Figures A-12, A-13, A-14, and A-15 and Table A-5 not included in this appendix]

- The objective of the entire process up to this point has been to produce an internally consistent set of baseline spillage for each spill source in each of the future years; these baselines must be acceptable to knowledgeable reviewers of the OPA 90 PRA

- A reference case will be selected and one or more alternative cases will support analyses of the sensitivity of the reference case to uncertainties in the several major input parameters

- Figures A-12 through A-15 (graphical representations of the values in Table A-5) present alternative baseline gallons spilled for each spill source for each year 1996–2025; each figure varies either the historical spill rate used or the traffic growth rate

- Figures A-12 and A-13 use the 1973–1990 spill rate and the low and high average annual oil traffic growth rate respectively

- Figure A-14 (proposed reference case) uses the 1981–1990 spill rate and the low average annual oil traffic growth rate; Figure A-15 uses the same historical spill rate but the high average annual oil traffic growth rate

Discussion Questions

- Is the described approach for projecting the proposed reference case of baseline spillage from each spill source over the forecast time period acceptable?

- Remember that two major estimates determine the final oil spill baselines—

    - Projected oil tonnage transported by tanker and barge

    - Historical average spill rates

  What changes would you recommend in the process or the individual estimates?

Forecasts of oil tanker traffic in PWS, Alaska

[Figure A-16 and Table A-6 not included in this appendix]

- Rule XI is directed at oil tankers serving Valdez, Alaska, via PWS

- Figure A-16 and Table A-6 present the projected baseline oil tanker traffic in PWS

- The decreasing oil tanker traffic in PWS is based on the assumption that this traffic is driven by total oil production in Alaska, which has been forecast by the State of Alaska, Department of Revenue, Oil and Gas Audit Division

- Projection through 2020 is based on the Fall 1996 Reference Case Forecast in the Revenue Source Book; the Volpe Center projection from 2020 extends the rate of decline to 2025

Discussion Questions

- Is this a realistic representation of future oil tanker traffic in PWS for the OPA 90 PRA?

- Should an alternative traffic scenario be considered, reflecting higher levels of oil transport via Valdez?

Baseline estimates of recovered spilled oil

[Figure A-17 not included in this appendix]

- Several OPA 90 rules address capabilities to contain and recover spilled oil (i.e., to increase the quantity of oil removed before substantive damage to the marine environment occurs)

- For purposes of the OPA 90 PRA, the average baseline spill recovery rate (within 72 hours) for the projected yearly spill quantities over the life cycle period will be assumed at 15 percent

- Figure A-17 graphically depicts the relationship between spillage and recovered spilled oil, the potential Expert Panel B effectiveness estimates, and the resulting OPA 90 benefit

- Several OPA 90 rules reduce the total oil spillage, a few rules increase the quantity of spilled oil recovered, and some do both

- OPA 90 total benefit is the reduced quantity of spilled oil remaining in the water represented by the difference between the baseline case and the OPA 90 case

Discussion Questions

- Is 15 percent an acceptable average baseline spill recovery rate for the period 1996–2025?

- If not, what would you recommend?

Baselines estimating considerations

- Application of OPA 90 rule effectiveness (to be estimated by Expert Panel B) to the oil spill baselines as described to this point may or may not overstate OPA 90 benefits because of—
    - Recent improvements in system operations
    - Other government (international, Federal, State, local) interventions

Discussion Questions

- Does this panel recommend the application of factors to adjust the baseline quantities to account for any of the above considerations?
- Would you recommend a single adjustment factor for all spill sources or a different adjustment factor for each?
- What adjustment factor or factors would you recommend?

Expert Panel B—Effectiveness of Selected OPA 90 Regulations

Requirements

- Five private-sector individuals, each with at least 10 years of relevant professional experience in 1 or more of the following.
  - Consulting/contractor/academia in marine oil transportation, oil spill prevention, spill response, environmental protection engineering, research, or planning
  - Master of Oil Tankers (retired) or Licensed Pilot (e.g., Delaware Bay Pilot)
  - Master of Oil Barge Tows (retired)
- Experience
  - Past service on NRC Marine Board Committee
  - Preparation of published initial OPA 90 RA
- Possess knowledge of tank vessel navigation and operations, tank vessel technology, tank vessel crew capabilities, training, experience, and performance
- In addition to the private-sector individuals, two Federal-agency personnel with expertise in oil transportation, oil spill prevention, and spill response were included on the panel.

Members

Keith Michel	Herbert Engineering Corporation
Henry S. Marcus	Marine Systems—Ocean Engineering, MIT
Jerry A. Aspland	President of California Maritime Academy
Greg DeMarco	ICF Kaiser Consulting Group
David C. Buchanan	Retired Vice President of Operation, MARITRANS

- LCDR Peter Neffenger — USCG Office of Investigations and Analysis
- Robert Gauvin — USCG Office of Operating and Environmental Standards

Workshop Advance Information Packet

Workshop—December 18–19, 1996; 8:00am–5:00pm. January 23, 1997; 8:00am–5:00pm.

Volpe National Transportation Systems Center, Cambridge, Massachusetts

Expert Panel B Instructions for Estimated OPA 90 Rules Effectiveness

Background

The Coast Guard has committed to prepare a comprehensive PRA, which accounts for the combined and interactive effects of regulations mandated by OPA 90 Titles IV and V.

As a member of a panel of experts, you will be asked to develop estimates of effectiveness attributable to the selected individual OPA 90 rules you have received in this packet of information. Please read through the Rules package [attachment not reproduced in this appendix, see Appendix B] first before proceeding. The panel will meet for 2 days to develop the estimates of effectiveness factors. Each rule will be considered in complete isolation from all other rules. Individual expert opinions will be collected after panel discussion on both the estimate (i.e., a number) as well as capturing discussion points. The panel need not come to consensus on the estimates themselves. All individual expert opinions will subsequently be combined into a matrix of effectiveness factors for computation of the overall benefit of OPA 90 rules as well as the benefit of each of the selected rules. These factors will be applied to projected yearly "baseline" oil spill data. This panel will have a chance to reconvene to review the results and make adjustments to their effectiveness estimates as necessary.

All expert panel percentage reduction estimates, opinions expressed in the panel workshops, and the combined effectiveness factors produced from them by the Volpe Center are the property of the Coast Guard and may not be disclosed by any participant.

Advance Preparation

Read through the rule descriptions. For each of the rules, the panel will be examining the impact of the rule upon four possible events—

1) Reduced number of vessel causalities/accidents

2) Reduced number of oil spills

3) Reduced quantity of oil spilled

4) Increased quantity of oil recovered

For the purposes of this panel we will consider the impact of the 11 groups of OPA 90 rules on four possible oil spill sources—

1) Tank ships underway

2) Tank barges underway

3) Lightering operations

4) Offshore and certain onshore facilities and docks (including tank vessels moored at these facilities and docks)

The Volpe Center, as part of our preparation, has mapped, by oil spill source, the appropriate event(s) or order(s) that may be affected by a given rule (see OPA 90 Estimates of Effectiveness Questionnaire and estimates of effectiveness chart [attachment not included in this appendix]). Not every rule affects every order, nor every oil spill source, so we have eliminated from the effectiveness charts those that do not apply.

To develop your estimates, assume for this exercise that you are estimating for the average facility, tank ship or tank barge in U.S. waters in average weather, under average conditions. It is important also to assume that OPA 90 rules are fully implemented.

A helpful way for estimating effectiveness percentages is to use the following.

- For every 100 accidents how many would be avoided if Rule X is applied?

- For every 100 spills how many would be avoided?

- For every 100 barrels of oil spilled, how many fewer would be spilled?

- For every 100 barrels of oil spilled, how many barrels would be recovered before substantive damage to the environment occurs?

Your answer can range from 0 (no effect) to 100 (completely eliminates that event). Again, each of your answers should be developed individually for each rule and in isolation from the impact of other rules.

Please review the OPA 90 Estimates of Effectiveness Questionnaire for the estimates that will be discussed during the panel meetings.

It is expected that each panel member will have followed through on these instructions, formed opinions, and arrives at the workshop prepared for discussion, but remains open to influence of the opinions of other experts on the panel. Your final estimates will be recorded at the workshop after due deliberation.

Summary Description of the Core Group of OPA 90 Rules

The panel was provided a list and description of the core group of 11 rules within the scope of the PRA. Refer to Appendix B for details on the core group rules.

Guidelines for Estimating Rule Effectiveness

Difficulties in Estimating Rules' Effectiveness Factors

Quantitative estimates of effectiveness (factors) of individual rules can be difficult to develop, since oil spills result from a complex set of influences. Some of these influences may be successfully addressed by a rule, while others may not be. For a given order of event (e.g., vessel casualty, accident, spill, or recovery operations) the effectiveness of a particular rule in preventing the occurrence of the order/event or minimizing its consequences will also depend on conditions such as weather, location, and other external circumstances. Moreover, discerning the effectiveness (improvement) associated with each individual rule—i.e., the incremental difference between OPA 90 rules and pre- or non-OPA 90 capabilities—can be troublesome. Another problem is that the OPA 90 rules are not all mutually exclusive nor are they necessarily independent of each other. This will result in interactive or duplicate effects among the individual rules. Simple summing of the individually estimated effectiveness factors of each rule would result in considerable "double counting" and thereby significantly overstate the overall effectiveness of the set of 11 core rules.

Solution

The Volpe team has developed a methodology to avoid the difficulty of double counting in the calculation of the Overall Effectiveness of the set of 11 core rules.

This methodology, however, requires—

- That the 11 core rules must initially be individually considered—alone in complete isolation—from the other rules and separate effectiveness factors be estimated for each isolated rule

- The judgments of this panel of experts as a supplemental resource for these estimates of effectiveness factors.[8]

Guidelines for Panelists

When you formulate your estimates of each rule's effectiveness factors, it is critical that you keep in mind the following.

- All effectiveness estimates should be based on expected values. That is, all estimates should assume and reflect a set of average external conditions or influences, and not be based on the most favorable or unfavorable situations possible.

- Absolutely no attempt should be made to adjust downward the effectiveness factor(s) of a rule due to any perceived interaction or double counting from any other rule or from the rule itself. Each rule's estimate of effectiveness factors must assume that this particular rule is the only OPA 90 rule in existence and that this rule's individual effectiveness factors do not affect one another.[9]

- An effectiveness factor of a particular rule on a particular spill source should be assigned a value of zero whenever that rule has no effect on that spill source or no effect on that specific event/order. Many of these combinations (rule-source pairs) do not occur and, so, almost all rules will have no impact on several of the events/orders. Moreover, for some of the rules the needed effectiveness factors for a specific spill source may be assumed to be identical (e.g., many rules' effectiveness factors may be identical for underway laden tank ships and tank barges).

- The effectiveness factors are percentages and their estimates can range from 0 to 100 percent.

- If a rule lowers the likelihood of a specific order/event by 25 percent, for example, then its effectiveness factor for this order/event would be 25 percent, not 75 percent.

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[8] Many of these effectiveness factors can be extracted or derived from each rule's RA; however, several of the RAs do not provide sufficient information for deriving effectiveness factors at this level of detail.

[9] Similarly, no attempt should be made to adjust downward the effectiveness factor(s) of a rule to reflect any known or perceived change in pre- or non-OPA 90 capabilities against these same events (this also excludes any adjustment to reflect pre- or non-OPA 90 rule compliance by some fraction of the vessel fleet). Such adjustments will be made by the Volpe Team; subsequently, Expert Panel B will be convened to review, validate, or recommend improvements.

Definition of a Rule's Effectiveness "Orders of Events"

Each of the 11 core rules has effectiveness factors. The rules' effectiveness factors are defined, however, only when each of the core rules is considered individually—alone in complete isolation—from the other rules. The individual rules' effectiveness events, are the following percentages.

- **First order event**: the percentage that an individual rule lowers the likelihood of an accident or failure involving oil transportation or a storage facility

- **Second order event**: the percentage that an individual rule lowers probability that a spill occurs (given that an accident or failure has occurred)

- **Third order event**: the percentage that an individual rule lowers the expected quantity of oil spilled (given that a spill has occurred)

- **Fourth order event**: the percentage that an individual rule increases the expected quantity of the spilled oil that would not remain (i.e., can be removed before damage) in the environment.

Each of the 11 core rules could have from one to as many as four effectiveness events (factors), since it is quite possible that some rules will affect more than one of these four events. Those rules confirmed to have more than one effectiveness order/event (factor) will require estimation of separate effectiveness factors for each order/event affected by the rule. The applicable spill sources of each rule may require a different set of effectiveness factors. Many of the effectiveness factors will be zero, since not all rules will affect all spill sources.

Estimating the Exchange Rate between Spillage Prevented and Spillage Recovered

Finally, you will be asked to assess the relative worth of any barrel of oil prevented from spilling versus the worth of any spilled barrel that is recovered (i.e., in sufficient time to avoid damage to the environment). That is to say, the worth of any 1st, 2nd, or 3rd order event barrel versus the worth of any 4th order event barrel. The relative weight that you will estimate is a dimensionless number, smaller than or equal to 1.0. The "worth" of 1st, 2nd, or 3rd order event barrels will be taken to be 1.0. Example: a weight of 0.20 would mean that you believe that a 4th order event barrel of oil is worth only 1/5 as much as a barrel not spilled.

OPA 90 Rule Effectiveness Questionnaire

RULE I. DOUBLE HULLS

For every 100 spills how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

RULE II. DECK SPILL CONTROL

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
- Lightering Operations? ____
- MTR Facilities and Docks? ____

RULE III. SPILL SOURCE CONTROL AND CONTAINMENT

For every 100 accidents how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

For every 100 spills how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____
- Lightering Operations? ____
- MTR Facilities and Docks? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____
- Lightering Operations? ____
- MTR Facilities and Docks? ____

For every 100 barrels of oil spilled, how many barrels would be recovered with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____
- Lightering Operations? ____
- MTR Facilities and Docks? ____

RULE IV. LIGHTERING OF SINGLE HULL VESSELS

For every 100 spills how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

RULE V. OVERFILL DEVICES

For every 100 spills how many would be avoided with this rule in effect for:
- Lightering Operations? ____
- MTR Facilities and Docks? ____

RULE VI. OPERATIONAL MEASURES OF SINGLE HULL VESSELS

For every 100 accidents how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

For every 100 spills how many would be avoided with this rule in effect for:
- Tank Ships underway? ____
- Tank Barges underway? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____

RULE VII. LICENSES, CERTIFICATES, AND MARINERS' DOCUMENTS

For every 100 accidents how many would be avoided with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

For every 100 spills how many would be avoided with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

RULE VIII. FINANCIAL RESPONSIBILITY

For every 100 accidents how many would be avoided with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

For every 100 spills how many would be avoided with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____
MTR Facilities and Docks? ____

RULE IX. VESSEL RESPONSE PLANS

For every 100 spills how many would be avoided with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____

For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____

For every 100 barrels of oil spilled, how many barrels would be recovered with this rule in effect for:
Tank Ships underway? ____
Tank Barges underway? ____
Lightering Operations? ____

RULE X FACILITY RESPONSE PLANS

For every 100 spills how many would be avoided with this rule in effect for:
MTR Facilities and Docks? ____
For every 100 barrels of oil spilled, how many fewer barrels would be spilled with this rule in effect for:
MTR Facilities and Docks? ____
For every 100 barrels of oil spilled, how many barrels would be recovered with this rule in effect for:
MTR Facilities and Docks? ____

RULE XI. PWS EQUIPMENT AND PERSONNEL REQUIREMENTS

For every 100 barrels of oil spilled, how many barrels would be recovered with this rule in effect for:

Tank Ships underway? ____

Final Issue for Expert Panel B:

- **Is a spilled barrel of oil that is recovered before damage to the marine environment worth less than a barrel of oil not spilled?**

  Yes? or No?

- **If yes, what factor (less than 1.00) would you apply to a barrel of oil not spilled to equal a spilled barrel of oil recovered?**

  Barrel Recovered = (0.xx) Barrel Not Spilled

OPA 90 PRA Expert Panel B Comments

The following notes were recorded by way of explanation of several of the panel estimates.

Rule I (Double Hulls)

The panel insisted on subdividing spill events into high energy and low energy casualties. Seven categories of vessel casualties were defined to deal with the differences. The effectiveness factors are applied to the portion of oil transport tons that is projected to be in double hulls each year as they phase-in 1996–2015.

Double hulls have negative side effects such as increased potential for fire and explosion caused, or aggravated, spills; increased spills from ballast handling if cargo tank leaking into outer hull, and added complexity of piping systems.

Rule II (Deck Spill Control)

Deck spill portion of lightering operations and facilities spills.

The panel member with the highest effectiveness estimate assumed only barges without coaming are affected.

Rule III (Spill Source Control and Containment)

Low effectiveness of booms, crew training, and low maintenance of containment equipment a problem.

Rule IV (Lightering of Single Hull Vessels)

Nondouble hull oil transport tons as they phase-out 1996–2015

Lightering equipment will not prevent spills and mitigation of spill is minor. Salvor brings his own equipment.

Rule V (Overfill Devices)

Overfill portion of lightering operations and facilities spills

Rule VI (Operational Measures of Single Hull Vessels)

Nondouble hull oil transport tons as they phase-out 1996–2015

Panel insisted upon estimating effectiveness of each of the 8 provisions separately, then summing.

Rule VII (Licenses, Certificates, and Mariners' Documents)

Rule VIII (Financial Responsibility)

Panel maintains that the concept of "unlimited liability" for claims and cleanup is driving safety improvements. Corporate culture change is necessary. Operators motivated to train personnel and focus on avoiding accidents and spills. Panel insisted upon differentiating between the effect of unlimited financial liability and the requirement for a Certificate of Financial Responsibility (COFR). The latter was assigned zero effectiveness by every member of the panel. The panel considered and rejected proposals to define subcategories and to estimate different effectiveness for each.

Rule IX (Vessel Response Plans)

Training of personnel heightens awareness and reduces accidents.

Rule X (Facility Response Plans)

Panel emphasized that their effectiveness estimates were based upon the PRA definition of Facility Baseline Spills (i.e., bunkering spills at anchorage as well as spills from vessels while at the dock are included).

Assume that all spills from the vessel, while at dock, are included in facilities spills.

Rule XI (PWS Equipment and Personnel Requirements)

PWS portion of the national total spills from tankers underway. Panel expressed the opinion that the effectiveness estimates for this rule should be attributed to the Alaska State Statutes and Regulations, which preceded OPA 90, not to the Federal Regulation that resulted from OPA 90. One Panel member recognized that the OPA 90 requirement for Citizen Advisory Group had powerful effect in PWS.

D. OIL SPILL BASELINE DATA

Table D-1
Oil Commodities Transported through U.S. Waters by Tankers and Barges, 1993
(Excluding Petroleum Coke and Liquid Natural Gas)

Commodity	Tankers (Thousand Tons)	Barges (Thousand Tons)	Total (Thousand Tons)	Percent
Crude Oil	456,021	42,919	498,940	57.46%
Residual Fuels	50,328	66,934	117,262	13.51
Gasoline	45,957	64,741	110,698	12.75
Kerosene and Distillates	41,234	45,703	86,937	10.01
Naptha, Solvents, and NEC	22,861	8,802	31,663	3.65
Lube, Grease, Jelly, and Wax	5,902	3,291	9,193	1.06
Asphalt, Tar, and Pitch	3,328	10,249	13,577	1.56
Total	625,631	242,639	868,270	100.00

ACOE, *Waterborne Commerce*

Table D-2
Total Bulk Transport by Tankers and Barges with 1 Percent Growth, Historical (1973–1995) and Forecasted (1996–2025), Per Expert Panel A

Year	All Vessels (Mil. Tons)	Tanker & Barge (Mil. Tons)	Tankers (Mil. Tons)	Barges (Mil. Tons)
1973	772.3	720.6	518.8	201.8
1974	755.7	705.0	507.6	197.4
1975	753.6	703.1	506.2	196.9
1976	856.5	799.2	575.4	223.8
1977	961.0	896.7	645.6	251.1
1978	997.0	930.2	669.7	260.5
1979	980.8	915.1	658.9	256.2
1980	903.2	842.7	606.7	236.0
1981	842.4	786.0	565.9	220.1
1982	799.6	746.0	537.1	208.9
1983	748.5	698.3	502.8	195.5
1984	753.5	703.0	506.2	196.8
1985	726.4	677.8	488.0	189.8
1986	815.6	761.0	547.9	213.1
1987	847.7	791.0	569.5	221.5
1988	887.7	828.2	596.3	231.9
1989	922.7	860.8	619.8	241.0
1990	923.5	861.7	620.4	241.3
1991	886.0	826.7	595.2	231.5
1992	899.6	839.3	604.3	235.0
1993	930.6	868.2	625.1	243.1
1994	961.3	896.9	645.8	251.1
1995	907.1	846.4	609.4	237.0
1996		864.0	624.5	239.5
1997		872.7	633.2	239.5
1998		881.4	641.9	239.5
1999		890.2	650.7	239.5
2000		899.1	659.6	239.5
2001		908.1	668.6	239.5
2002		917.2	677.7	239.5
2003		926.4	686.9	239.5
2004		935.6	696.1	239.5
2005		945.0	705.5	239.5
2006		954.4	714.9	239.5
2007		964.0	724.5	239.5
2008		973.9	734.4	239.5
2009		983.4	743.9	239.5
2010		993.2	753.7	239.5
2011		1,003.1	763.6	239.5
2012		1,013.2	773.7	239.5
2013		1,023.3	783.8	239.5
2014		1,033.5	794.0	239.5
2015		1,043.9	804.4	239.5
2016		1,043.9	804.4	239.5
2017		1,043.9	804.4	239.5
2018		1,043.9	804.4	239.5
2019		1,043.9	804.4	239.5
2020		1,043.9	804.4	239.5
2021		1,043.9	804.4	239.5
2022		1,043.9	804.4	239.5
2023		1,043.9	804.4	
2024		1,043.9	804.4	
2025		1,043.9	804.4	

All Vessels, ACOE data. 1973–1995 = 0.933 × All vessel tons from ACOE data to exclude petroleum coke and liquid natural gas. 1996–2025 = 1991–1995 average × 1.01/year. Tanker 1973–1995 = Total × 0.72. Tanker 1996–2025 = Total - Barge. Barge 1973–1995 = Total × 0.28. Barge 1996–2025 = 1991–1995 average held constant.

Table D-3
Total Bulk Transport by Tankers and Barges with 3 Percent Growth, Historical (1973–1995) and Forecasted (1996–2025), Per Expert Panel A

Year	All Vessels (Mil. Tons)	Tanker & Barge (Mil. Tons)	Tankers (Mil. Tons)	Barges (Mil. Tons)
1973	772.3	720.6	518.8	201.8
1974	755.7	705.0	507.6	197.4
1975	753.6	703.1	506.2	196.9
1976	856.5	799.2	575.4	223.8
1977	961.0	896.7	645.6	251.1
1978	997.0	930.2	669.7	260.5
1979	980.8	915.1	658.9	256.2
1980	903.2	842.7	606.7	236.0
1981	842.4	786.0	565.9	220.1
1982	799.6	746.0	537.1	208.9
1983	748.5	698.3	502.8	195.5
1984	753.5	703.0	506.2	196.8
1985	726.4	677.8	488.0	189.8
1986	815.6	761.0	547.9	213.1
1987	847.7	791.0	569.5	221.5
1988	887.7	828.2	596.3	231.9
1989	922.7	860.8	619.8	241.0
1990	923.5	861.7	620.4	241.3
1991	886.0	826.7	595.2	231.5
1992	899.6	839.3	604.3	235.0
1993	930.6	868.2	625.1	243.1
1994	961.3	896.9	645.8	251.1
1995	907.1	846.4	609.4	237.0
1996		881.2	641.6	239.5
1997		907.6	668.1	239.5
1998		934.8	695.3	239.5
1999		962.9	723.4	239.5
2000		991.7	752.2	239.5
2001		1,021.5	782.0	239.5
2002		1,052.1	812.6	239.5
2003		1,083.7	844.2	239.5
2004		1,116.2	876.7	239.5
2005		1,149.7	910.2	239.5
2006		1,184.2	944.7	239.5
2007		1,219.7	980.2	239.5
2008		1,256.3	1,016.8	239.5
2009		1,294.0	1,054.5	239.5
2010		1,332.8	1,093.3	239.5
2011		1,372.8	1,133.3	239.5
2012		1,414.0	1,174.5	239.5
2013		1,456.4	1,216.9	239.5
2014		1,500.1	1,260.6	239.5
2015		1,545.1	1,305.6	239.5
2016		1,591.5	1,352.0	239.5
2017		1,639.2	1,399.7	239.5
2018		1,688.4	1,448.9	239.5
2019		1,739.0	1,499.5	239.5
2020		1,791.2	1,551.7	239.5
2021		1,844.9	1,605.4	239.5
2022		1,900.3	1,660.8	239.5
2023		1,957.3	1,717.8	239.5
2024		2,016.0	1,776.5	239.5
2025		2,076.5	1,837.0	239.5

All Vessels, ACOE data. 1973–1995 = 0.933 × All vessel tons from ACOE data to exclude petroleum coke and liquid natural gas. 1996–2025 = 1991–1995 average × 1.03/year. Tanker 1973–1995 = Total × 0.72. Tanker 1996–2025 = Total - Barge. Barge 1973–1995 = Total × 0.28. Barge 1996–2025 = 1991–1995 average held constant.

Table D-4
Single Hull Phase Out Schedule in DWT, Per Expert Panel A

Year	Jones Act T&B Capacity	Jones Act Tanker & Barge Single Hull	International Tanker Single Hull Cumulative Deletions	International Single Hulls	Jones Act + International = Total Single Hulls	Total Single Hull Capacity Factor for OPA 90
	(a)	(b)	(c)	(d)	(e)	(f)
1990						0.920
1991						0.909
1992						0.898
1993						0.887
1994				219,015,553		0.876
1995	9,304,681	8,037,799	695,838	218,319,715	223,357,514	0.865
1996	9,165,091	7,898,209	1,528,019	217,487,534	225,385,743	0.864
1997	9,084,257	7,817,375	2,425,616	216,589,937	224,407,312	0.858
1998	8,755,112	7,488,230	4,811,673	214,203,880	221,692,110	0.847
1999	8,399,041	7,132,159	20,740,848	198,274,705	205,406,864	0.785
2000	7,280,769	6,013,887	33,755,966	185,259,587	191,273,474	0.731
2001	6,749,108	5,482,226	38,718,019	180,297,534	185,779,760	0.710
2002	6,253,735	4,986,853	44,976,557	174,038,996	179,025,849	0.684
2003	6,007,952	4,741,070	57,550,934	161,464,619	166,205,689	0.635
2004	5,472,221	4,205,339	76,641,256	142,374,297	146,579,636	0.560
2005	4,142,837	2,875,955	98,293,467	120,722,086	123,598,041	0.472
2006	3,242,028	1,975,146	119,869,308	99,146,245	101,121,391	0.386
2007	2,842,258	1,575,376	132,974,242	86,041,311	87,616,687	0.335
2008	2,490,186	1,223,304	139,551,368	79,464,185	80,687,489	0.308
2009	2,233,628	966,746	145,025,876	73,989,677	74,956,423	0.286
2010	1,959,443	692,561	162,718,960	56,296,593	56,989,154	0.218
2011	1,787,069	520,187	164,636,563	54,378,990	54,899,177	0.210
2012	1,534,219	267,337	165,574,514	53,441,039	53,708,376	0.205
2013	1,420,792	153,910	166,934,386	52,081,167	52,235,077	0.200
2014	1,420,792	153,910	168,724,319	50,291,234	50,445,144	0.193
2015	1,266,882	0	219,015,553	0	0	0.000
2016			219,015,553			
2017			219,015,553			
2018			219,015,553			
2019			219,015,553			
2020			219,015,553			
2021			219,015,553			
2022			219,015,553			
2023			219,015,553			
2024			219,015,553			
2025			219,015,553			

(a) Input from Expert Panel A
(b) Assumes double-hull capacity constant at 1,266,882
(c) Input from Expert Panel A
(d) Assumes 219,015,553 = 1994 single-hull capacity
(e) (b) + (d)
(f) 1990 = 92 percent single hull; 1995 = 86.5 single hull; 1996–2025 = (f) × annual reduction (e)

Table D-5
Nondouble Hull Phase Out Schedule, Per Expert Panel A

Year	Total Fleets Nondouble Hull Transport (Mil. Tons, 1996–2025 @ 1 Percent/Yr)	OPA 90 T&B Total Transport (Mil. Tons, 1996–2025 @ 1 Percent/Yr)	Total Fleets Non-D.H. Cap. Factor Apply to OPA 90 Total T&B Tons
1973		720.6	
1974		705.1	
1975		703.1	
1976		799.1	
1977		896.6	
1978		930.2	
1979		915.1	
1980		842.7	
1981		786.0	
1982		746.0	
1983		698.4	
1984		703.0	
1985		677.7	
1986		761.0	
1987		790.9	
1988		828.2	
1989		860.9	
1990	792.7	861.6	0.920
1991	751.4	826.6	0.909
1992	753.7	839.3	0.898
1993	770.1	868.2	0.887
1994	785.7	896.9	0.876
1995	732.1	846.3	0.865
1996	744.2	864.0	0.861
1997	748.4	872.7	0.858
1998	746.7	881.4	0.847
1999	698.8	890.2	0.785
2000	657.2	899.1	0.731
2001	644.7	908.1	0.710
2002	627.5	917.2	0.684
2003	588.4	926.4	0.635
2004	524.1	935.6	0.560
2005	446.3	945.0	0.472
2006	368.8	954.4	0.386
2007	322.8	964.0	0.335
2008	300.2	973.6	0.308
2009	281.7	983.4	0.286
2010	216.3	993.2	0.218
2011	210.4	1,003.1	0.210
2012	207.9	1,013.2	0.205
2013	204.3	1,023.3	0.200
2014	199.2	1,033.5	0.193
2015	0.0	1,043.9	0.000
2016		1,043.9	
2017		1,043.9	
2018		1,043.9	
2019		1,043.9	
2020		1,043.9	
2021		1,043.9	
2022		1,043.9	
2023		1,043.9	
2024		1,043.9	
2025		1,043.9	

Table D-6
Prince William Sound, Alaska, OPA 90 Tanker Traffic

Year	ACOE Data Tank Ship (Million Tons)	AK Production Oil & Gas Audit Division, Department of Revenue (Mil. Barrels/Day)	AK Annual Change Factor	PWS OPA 90 Tanker Traffic (Million Tons)
		(a)		
1989		1.960		
1990		1.853	0.9454	93.88
1991		1.800	0.9714	91.20
1992		1.791	0.9950	90.74
1993	85.623	1.690	0.9436	85.62
1994		1.641	0.9710	83.14
1995		1.574	0.9592	79.75
1996		1.475	0.9371	74.73
1997		1.429	0.9688	72.40
1998		1.373	0.9608	69.56
1999		1.293	0.9417	65.51
2000		1.288	0.9961	65.26
2001		1.308	1.0155	66.27
2002		1.240	0.9480	62.82
2003		1.164	0.9387	58.97
2004		1.080	0.9278	54.72
2005		1.007	0.9324	21.05
2006		0.938	0.9315	47.52
2007		0.878	0.9360	44.48
2008		0.823	0.9374	41.70
2009		0.772	0.9380	39.11
2010		0.734	0.9508	37.19
2011		0.694	0.9455	35.16
2012		0.658	0.9481	33.34
2013		0.623	0.9468	31.56
2014		0.590	0.9470	29.89
2015		0.563	0.9542	28.52
2016		0.538	0.9556	27.26
2017		0.505	0.9387	25.59
2018		0.462	0.9149	23.41
2019		0.428	0.9264	21.68
2020		0.396	0.9252	20.06
2021		0.366	0.9252	18.56
2022		0.339	0.9252	17.17
2023		0.314	0.9252	15.89
2024		0.290	0.9252	14.70
2025		0.269	0.9252	13.60

(a) Projection through 2020 from Fall 1996 Reference Case Forecast, Revenue Sources Book, Alaska Department of Revenue; 2021–2025 projected at constant rate of decrease.

Table D-7
Number of Oil Spills, 1973–1995

Year	Tankers	Barges	Lightering Operations	Facilities	Annual Total
1973	34	65	0	3,818	3,917
1974	34	66	0	4,077	4,177
1975	34	63	0	3,181	3,278
1976	26	63	9	3,221	3,319
1977	26	85	22	3,219	3,352
1978	20	69	25	3,118	3,232
1979	30	50	18	2,748	2,846
1980	14	60	14	2,725	2,813
1981	17	37	16	2,696	2,766
1982	10	52	11	2,641	2,714
1983	10	47	12	2,858	2,927
1984	18	50	21	2,583	2,672
1985	10	30	8	5,052	5,100
1986	11	36	31	1,858	1,936
1987	7	28	13	1,652	1,700
1988	16	30	22	1,728	1,796
1989	14	40	22	2,327	2,403
1990	19	45	34	2,971	3,069
1991	15	22	22	2,996	3,055
1992	1	7	9	2,526	2,543
1993	1	7	13	2,923	2,944
1994	18	39	17	3,023	3,097
1995	7	13	7	2,447	2,474
Total	392	1,004	346	65,388	68,130

Table D-8
Gallons of Oil Spilled, 1973–1995

Year	Tankers	Barges	Lightering Operations	Facilities	Annual Total
1973	478,248	753,033	0	1,984,594	3,215,875
1974	293,353	2,028,213	0	1,491,243	3,812,809
1975	7,825,786	2,352,085	0	1,417,300	11,595,171
1976	8,125,815	766,284	539	2,389,685	11,282,323
1977	14,257	1,179,757	1,785	1,032,850	2,228,649
1978	97,832	1,576,666	2,350	2,092,411	3,769,259
1979	11,857,531	762,919	1,094	1,134,424	13,755,968
1980	106,727	882,808	1,038	2,173,539	3,164,112
1981	945,984	249,378	9,460	669,861	1,874,683
1982	1,053,172	1,848,691	38,166	769,022	3,709,051
1983	628	1,680,174	3,998	603,770	2,288,570
1984	4,355,252	2,134,751	723	723,318	7,214,044
1985	676,144	2,206,494	165	490,597	3,373,400
1986	370,733	881,933	58,183	1,609,733	2,920,582
1987	602,993	399,702	4,841	441,254	1,448,790
1988	685,350	2,775,385	67,402	2,265,525	5,793,662
1989	11,109,715	440,624	23,039	697,105	12,270,483
1990	288,869	644,650	3,906,073	1,482,999	6,322,591
1991	40,049	150,837	1,077	513,399	705,362
1992	989	27,210	2,247	709,541	739,987
1993	10	254,181	35,075	341,447	630,713
1994	48,857	82,139	546	491,024	622,566
1995	66	21,019	77,173	879,269	977,527
Total	48,978,360	24,098,933	4,234,974	26,403,910	103,716,177

Table D-9
Period Spills and Million Tons Transported

Time Period	Tankers	Barges	Lightering Operations	Facilities	Tanker & Barge Transport (Million Tons)
1981–1990	132	395	190	23,366	7,714
1973–1990	350	916	278	49,473	14,226
1973–1980	218	521	88	26,107	6,512

Table D-10
Historic Spill Rates (Number of Spills per Million Tons Transported)

Time Period	Tankers	Barges	Lightering Operations	Facilities
1981–1990	0.02	0.18	0.03	3.03
1973–1990	0.03	0.23	0.03	3.48
1973–1980	0.05	0.11	0.02	5.57

Table D-11
Period Oil Spillage and Million Tons Transported

Time Period	Tankers	Barges	Lightering Operations	Facilities	Tanker & Barge Transport (Million Tons)
1981–1990	20,088,840	13,261,782	4,112,050	9,753,184	7,714
1973–1990	48,888,389	23,563,547	4,118,856	23,469,230	14,226
1973–1980	28,799,549	10,301,765	6,806	13,716,046	6,512

Table D-12
Historic Spillage Rates (Gallons per Million Tons Transported)

Time Period	Tankers	Barges	Lightering Operations	Facilities
1981–1990	3,617	6,140	740	1,264
1973–1990	4,773	5,916	402	1,650
1973–1980	6,142	5,650	1	2,106

Table D-13
Oil Spill Baselines (in Thousands of Gallons) by Spill Source, 1 Percent Growth per Year 1996–2015

Year	Tankers	Barges	Lightering Operations	Facilities
1973	478	753	0	1,985
1974	293	2,028	0	1,491
1975	7,826	2,352	0	1,417
1976	8,126	766	1	2,390
1977	14	1,180	2	1,033
1978	98	1,577	2	2,092
1979	11,858	763	1	1,134
1980	107	883	1	2,174
1981	946	249	9	670
1982	1,053	1,849	38	769
1983	1	1,680	4	604
1984	4,355	2,135	1	723
1985	676	2,206	0	491
1986	371	882	58	1,610
1987	603	400	5	441
1988	685	2,775	67	2,266
1989	11,110	441	23	697
1990	289	645	3,906	1,483
1991	40	151	1	514
1992	1	27	2	710
1993	0	254	35	341
1994	49	82	1	491
1995	0	21	77	879
1996	2,259	1,471	462	1,093
1997	2,290	1,471	469	1,104
1998	2,322	1,471	475	1,115
1999	2,354	1,471	482	1,126
2000	2,386	1,471	488	1,137
2001	2,418	1,471	495	1,148
2002	2,451	1,471	502	1,160
2003	2,484	1,471	508	1,171
2004	2,518	1,471	515	1,183
2005	2,552	1,471	522	1,195
2006	2,586	1,471	529	1,207
2007	2,620	1,471	536	1,219
2008	2,655	1,471	543	1,231
2009	2,691	1,471	551	1,243
2010	2,726	1,471	558	1,256
2011	2,762	1,471	565	1,268
2012	2,798	1,471	573	1,281
2013	2,835	1,471	580	1,294
2014	2,872	1,471	588	1,307
2015	2,909	1,471	595	1,320
2016	2,909	1,471	595	1,320
2017	2,909	1,471	595	1,320
2018	2,909	1,471	595	1,320
2019	2,909	1,471	595	1,320
2020	2,909	1,471	595	1,320
2021	2,909	1,471	595	1,320
2022	2,909	1,471	595	1,320
2023	2,909	1,471	595	1,320
2024	2,909	1,471	595	1,320
2025	2,909	1,471	595	1,320

E. PROCEDURE TO ESTIMATE THE OVERLAPPING BENEFIT OF OPA 90

This appendix gives the details of the 20-step comprehensive Procedure that computes OPA 90 benefits without double counting.

An individual rule's effectiveness factors, the OPA 90 overall effectiveness factor, and yearly overall benefits were computed using "expected values." This assumed that expected casualties and failures, expected spill sizes, and expected amounts of oil recovered from the water were linearly comparable. For example, using expected values treated the first barrel recovered from an oil spill the same as the last barrel recovered. Additionally, decision makers were assumed to be risk neutral, which means that the value of avoiding a 10 million-barrel spill, with a yearly probability of one in a million, has the same worth as avoiding a 100-barrel spill, with a yearly probability of one in 10. While this was a simplifying assumption, the Coast Guard believes that a risk-neutral model yields good estimates of real-world scenarios. At Coast Guard's request, a sensitivity analysis values barrels of oil prevented from being spilled differently than barrels spilled and then recovered in a timely fashion (see Chapter 9).

The Procedure estimated the overall and marginal impacts of a core group of 11 OPA 90 rules, each with possibly four orders of effectiveness and four different sources of oil spills for each year of the assessment period (1996–2025). The procedure adjusted the impacts of the OPA 90 rules to avoid potential double counting. The computation of impacts used the following symbols.

- i, represents the specific source of oil spills (i = 1 to 4)
- N, represents the number of rules whose effectiveness factor or benefit the Procedure is computing (N = 1 to 11)
- Yr, represents the specific year of the effectiveness factor or benefit (Yr = 1996 to 2025)
- B, represents benefits
- TPB, represents total potential benefits

The Procedure is comprised of two parts.

1) Part 1—Overall Effectiveness

i, specific source of oil spills ($i = 1$ to 4)
N, number of rules ($N = 1$ to 11)
YR, specific year ($Yr = 1996$ to 2025)

a) For each of the four sources of oil spills, i, the $Overall_i$ Effectiveness Factor of all N rules joined together as one distinct, whole entity

b) For each of the four sources of oil spills, i, the expected yearly $Overall_i$ $Benefits_{Yr}$ that are a consequence of this $Overall_i$ Effectiveness Factor and the expected yearly Overall $Benefits_{Yr}$ by summing the $Overall_i$ $Benefits_{Yr}$ over all the i's

c) The Total Present Value (TPV) of this stream of overall benefits[10]

d) The overall cost effectiveness of all N rules joined together as one entity (or the overall cost effectiveness of any subset of these N rules)

The overall cost effectiveness is measured in \$/BNSR and is the ratio of TPV of the stream of yearly overall costs to the TPV of the stream of yearly expected overall benefits over the same assessment period. The above four tasks can also be performed on any subset of the N rules to get that subset's $Overall_i$ Effectiveness Factor, $Overall_i$ $Benefits_{Yr}$, etc. See Chapter 3 again for the discussion of overall effectiveness.

[10] A rate of 7 percent is used to discount both yearly costs and yearly benefits back to the base year, 1996.

i, specific source of oil spills (i = 1 to 4)
N, number of rules (N = 1 to 11)
YR, specific year (Yr = 1996 to 2025)

2) Part 2—Marginal Effectiveness

a) The marginal effectiveness that any particular rule J, J = 1 to N, contributes to the overall effectiveness factor of the other N - 1 rules' effectiveness (designated by sub-overall) when these N - 1 rules are considered as one distinct whole entity

b) The yearly expected marginal benefits that are a consequence of this particular rule's marginal effectiveness

c) The TPV of the stream of yearly expected marginal benefits

d) The cost effectiveness of these marginal benefits (measured in $/BNSR), also referred to as the marginal cost effectiveness of each rule

The Procedure

Analyses must keep separate account of a core group of 11 different rules, each with one to possibly four distinct orders of individual effectiveness (considered in complete isolation from all other rules), and one to four different sources of oil spills for each year of the assessment period.

Step 1

Enter the four shares (percentages) that each of the four distinct sources of oil spills makes up of the total volume of oil transported or stored in the base year 1996.

Step 2

For each of the years, calculate the yearly expected value of the amount of oil each of the four sources would spill with none of the rules in place, as well as the yearly expected value of the amount of oil that would be removed from the environment with none of the rules in place (construction of the event tree is not explicitly required). For each year of the 30-year assessment period and for each of the four sources, i, i = 1 to 4, find the 120 = 30 × 4 yearly baseline cases, i.e., the yearly expected total potential benefits,[11] TPB_{iYr}, that result from subtracting the yearly expected amount of oil removed from the environment with none of the rules in place, from the yearly expected amount spilled with none of the rules in place. PRAAM will automatically compute these 120 values by using the shares entered in Step 1 and a yearly growth factor.

[11] Yearly expected total potential benefits are presented for each source, i, by "TPB_{iYr}," since, in general, they will vary by year and source because the amount of oil that will be transported (or stored) varies by year.

Step 3

For each of the 4 sources, i, of spills and for each rule analyzed, four pieces of information are needed: what four percentages to choose for the first, second, third, and fourth order effectiveness factors (many will be zero) when the rule is considered in total isolation from all the other rules (see Chapter 3). For each rule and each of the four sources, i, obtain the first order effectiveness factor attributable only to this specific rule when considered in complete isolation from all the other rules, i.e., find the percentage reduction in expected accidents by this rule considered alone from all the others (many of the first order effectiveness factors will be zero).

Step 4

Take these first order effectiveness factors (which have yet to be adjusted for double counting). For each of the four spill sources, i, i = 1 to 4, there will be N first order factors, $e1_{i1}$, $e1_{i2}$, $e1_{i3}$,.,., $e1_{iN}$, one for each of the N rules sequenced by rule index, J = 1 to N, and enter each of the four N-tuples into the four first order data entry columns.

Step 5

The Procedure will automatically calculate the Grand_i First Order Effectiveness for each of four spill sources, i, by taking the 1 by N row vector $v1_i = (e1_{i1}, e1_{i2}, e1_{i3}, .,.e1_{iN})$, and the transposition of the 1 by N row vector,[12] $v1_{iEDC}$ =

$(1, 1 - e1_{i1}, 1 - [e1_{i1} + (1 - e1_{i1}) \times e1_{i2}], 1 - \{e1_{i1} + (1 - e1_{i1}) \times e1_{i2} + [1 - (e1_{i1} + (1 - e1_{i1}) \times e1_{i2}] \times e1_{i3}\}$,.,.,., ...etc., etc.,........, $1 - \{e1_{i1} + (1 - e1_{i1}) \times e1_{i2} + [1 - (e1_{i1} + (1 - e1_{i1}) \times e1_{i2}] \times e1_{i3} +$ ...etc., etc.,... $\times e1_{iN})$ and computing the two vectors' dot product. The resultant dot product (which will be a number, not a vector) is the Grand_i First Order Effectiveness, $\text{GrandE}1_i$. It will be totally free from any double counting that could have arisen from any of factors $e1_{i1}$, $e1_{i2}$, $e1_{i3}$,.,., $e1_{iN}$.

The reader may have noticed the *recursive* nature of the required computations performed in Step 5; this recursiveness will also appear in Steps 8, 11, 14, and 15. PRAAM was designed to exploit this recursiveness, rendering the entire process much more tractable.

Step 6

For each rule and for each source, i, obtain the second order effectiveness factor attributable only to this specific rule when considered in complete isolation from all the rules, i.e., find the

[12] The vector, $v1_{iEDC}$ stands for the eliminating double counting vector.

percentage reduction in expected spills (given an accident has occurred) by this rule considered alone from all the others (many of the second order effectiveness factors will be zero).

Step 7

Take these second order effectiveness factors (which have yet to be adjusted for double counting). For each of the four spill sources, i, i = 1 to 4, there will be N second order factors, $e2_{i1}$, $e2_{i2}$, $e2_{i3}$,.,.,., $e2_{iN}$, one for each the N rules sequenced by rule index, J = 1 to N, and enter each of the four N-tuples into the four second order data entry columns.

Step 8

The Procedure will, by exploiting the recursive nature of the required computation, automatically calculate the Grand_i Second Order Effectiveness for each of the four spill sources, i. The resultant number is the Grand_i Second Order Effectiveness, GrandE2_i. It will totally free from any double counting that could have arisen from any of the factors $e2_{i1}$, $e2_{i2}$, $e2_{i3}$,.,., $e2_{iN}$.

Step 9

For each rule and for each source, i, obtain the third order effectiveness factor attributable only to this specific rule when considered in complete isolation from all the rules, i.e., find the percentage reduction in expected spill size (given a spill has occurred) by this rule considered alone from all the others (many of the third order effectiveness factors will be zero).

Step 10

Take these third order effectiveness factors (which have yet to be adjusted for double counting). For each of the four spill source sources, i, i = 1 to 4, there will be N third order factors, $e3_{i1}$, $e3_{i2}$, $e3_{i3}$,.,.,., $e3_{iN}$, one for each of the N rules sequenced by rule index, J = 1 to N, and enter each of the four N-tuples into the four third order data entry columns.

Step 11

The Procedure will, by exploiting the recursive nature of the required computation, automatically calculate the Grand_i Third Order Effectiveness for each of four spill sources, i. The resultant number is the Grand_i Third Order Effectiveness, GrandE3_i. It will be totally free from any double counting that could have arisen from any of the factors $e3_{i1}$, $e3_{i2}$, $e3_{i3}$,.,., $e3_{iN}$.

Step 12

For each rule and for each source, i, obtain the fourth order effectiveness factor attributable only to this specific rule by finding the expected percentage reduction in the amount of oil that remains in the environment, given that some oil has remained in the environment (many of the fourth order effectiveness factors will be zero).

Step 13

Take these fourth order effectiveness factors (which have yet to be adjusted for double counting). For each of the four spill sources, i, i = 1 to 4, there will be N fourth order factors, $e4_{i1}$, $e4_{i2}$, $e4_{i3}$,.,.,., $e4_{iN}$, one for each of the N rules sequenced by rule index, J = 1 to N, and enter each of the four N-tuples into the four fourth order data entry columns of the spreadsheet.

Step 14

The Procedure will, by exploiting the recursive nature of the required computation, automatically calculate the $Grand_i$ Fourth Order Effectiveness for each of 4 sources, i. The resultant number is the $Grand_i$ Fourth Order Effectiveness, $GrandE4_i$. It will be totally free from any double counting that could have arisen from any of the factors $e4_{i1}$, $e4_{i2}$, $e4_{i3}$,.,., $e4_{iN}$.

Step 15

For each of the 4 sources, i, let $E1_i$, $E2_i$, $E3_i$, and $E4_i$ stand for $GrandE1_i$, $GrandE2_i$, $GrandE3_i$, and $GrandE4_i$, respectively. For each of the four spill sources, i, the Procedure will, by exploiting the recursive nature of the required computation, automatically calculate the $Overall_i$ Effectiveness Factor, $OverallEff_i$, in a manner analogous to that used above. Each of the four (i = 1 to 4) $OverallEff_i$ will be free from any double counting that could have arisen from any of $E1_i$, $E2_i$, $E3_i$, $E4_i$.

Step 16

For each of the four spill sources, i, the Procedure multiplies the four, separate $Overall_i$ Effectiveness Factors, $OverallEff_i$ by their corresponding yearly expected total potential benefits, TPB_{iYr}, which were computed in Step 2. This will give us the yearly expected $Overall_i$ Benefits (undiscounted) for each year, Yr (Yr = 1996 to 2025) for each of the four sources, i.

i, specific source of oil spills (i = 1 to 4)
N, number of rules (N = 1 to 11)
YR, specific year (Yr = 1996 to 2025)

Step 17

The Procedure first adds all the expected overall benefits by source, $Overall_i$ Benefits, of each source together to calculate total benefits, TB_{Yr}, for each year then discounts each year's total by 7 percent over the assessment period back to the base year, 1996. It then sums these discounted yearly expected overall benefits, giving us TPVB, the TPV of the yearly expected overall benefits.

Step 18

Enter the four yearly costs of rules (one for each source i)—each rule's corresponding yearly expected total cost (undiscounted) for the four sources. Because most of the rules will affect only a single source, many of these yearly rule costs will be zero. For each of the assessment period years, the Procedure adds each of the rule's corresponding yearly expected total costs (undiscounted), getting four (one for each source) sets of yearly $Overall_i$ Costs.

Step 19

The Procedure first adds all the expected costs of each source together to get total costs, TC_{Yr}, for each year; then discounts each of them by 7 percent over the assessment period back to the base year, 1996. It then sums these discounted yearly expected overall costs, giving us TPVC, the TPV of the yearly expected total costs.

Step 20

Finally, the Procedure calculates the overall cost effectiveness ratio by dividing the TPVC (in dollars) by the TPVB (in BNSR).

Illustrative Example

For each rule analyzed, three crucial pieces of information are needed—

1) Which spill source or sources the rule affects

2) To which order or orders (see Chapter 3) it belongs

3) What percent to select in estimating the effectiveness factor or factors of that rule's impact (when considered in total isolation from all the other rules) on each of the four classes' corresponding, defining events.

Suppose that the overall effectiveness factor of a set of two rules is to be computed: Rule A and Rule B, joined together and considered as one single, whole entity. Assume that each rule only affects one source, namely oil tankers underway. Suppose Rule A (when considered alone from B) has the four effectiveness factors (0.40, 0.10, 0.05, 0.10). Suppose that Rule B (when considered alone from A) has the four effectiveness factors (0.30, 0.05, 0.55, 0.0). One computes the overall effectiveness factor of these two rules, when joined together as a whole, in the following way.

Find the grand first order effectiveness factor by examining the individual first order effectiveness factors of Rule A and Rule B, 0.40 and 0.30, respectively. The grand first order effectiveness factor of Rules A and B (considered together as a whole) will be $0.40 + (1 - 0.40) \times 0.30 = 0.58$. One then computes the grand second order effectiveness factor as $0.10 + (1 - 0.10) \times 0.05 = 0.145$. Similarly, the grand third order effectiveness factor and grand fourth order effectiveness factor are computed to be $0.05 + (1 - 0.05) \times 0.55 = 0.5725$ and $0.10 + (1 - 0.10) \times 0.00 = 0.10$, respectively.

One can now form the new effectiveness vector that is associated with Rules A and B (joined together as a whole) by listing in ordered sequence each of our computed grand first, grand second, grand third, and grand fourth order effectiveness factors (0.58, 0.145, 0.5725, 0.10). Next, compute the overall effectiveness factor of these two rules joined together—

$$0.58 + (1 - 0.58) \times 0.145 + [1 - (0.58 + (1 - 0.58) \times 0.145)] \times 0.5725 + \{1 - [0.58 + (1 - 0.58) \times 0.145 + (1 - (0.58 + (1 - 0.58) \times 0.145)) \times 0.5725]\} \times 0.10$$

$$= 0.58 + 0.0609 + [1 - (0.58 + 0.0609)] \times 0.5725 + \{1 - [0.58 + 0.0609 + (1 - (0.58 + 0.0609)) \times 0.5725]\} \times 0.10$$

$$= 0.6409 + [1 - (0.6409)] \times 0.5725 + \{1 - [0.6409 + (1 - 0.6409) \times 0.5725]\} \times 0.10$$

$$= 0.6409 + 0.2056 + \{1 - [0.6409 + 0.2056]\} \times 0.10 = 0.6409 + 0.2056 + 0.01535 = 0.8618363 \cong 0.86$$

Notice that after the grand first order effectiveness factor of the joined rules of the example has been applied, only 1 - 0.58 or approximately 42 percent of the original total potential benefits, TPB_{Yr}, remain. After the grand first and grand second order effectiveness factors of the joined rules have been applied, only 1 - 0.6409 or approximately 36 percent of the original TPB_{Yr} remain. After the grand first, grand second, and grand third order effectiveness factors of the joined rules have been applied, only 1 - 0.8465 or approximately 15 percent of the original TPB_{Yr} remain. Finally, after the grand first, grand second, grand third, and grand fourth order

i, specific source of oil spills (i = 1 to 4)
N, number of rules (N = 1 to 11)
YR, specific year (Yr = 1996 to 2025)

effectiveness factors of the joined rules have been applied, only 1 - 0.8618 or approximately 14 percent of the original TPB_{Yr} remain.[13]

The Marginal Effectiveness of a Particular Rule

It is necessary to compute, without any double counting, the marginal effectiveness that each Rule J, J = 1 to N, contributes to the overall effectiveness of the other N - 1 rules' effectiveness when these N - 1 rules are considered as one entity. It is also necessary to determine the marginal benefits of each Rule J and the marginal cost effectiveness of each Rule J.

The $Marginal_J$ Effectiveness of a particular Rule J is the difference between the overall effectiveness of all N of the rules considered together as one entity and the overall effectiveness of the other N - 1 rules considered together after Rule J has been excluded, where the overall effectiveness of any set of rules is the weighted average of the four $Overall_i$ Effectiveness factors. The weight used for each $Overall_i$ will be the normalized source-spill volume for that source, i, (the normalization consists of dividing each of the source-spill volumes by their total sum).

Also, the $Marginal_J$ Benefit of this particular Rule J is simply the $Marginal_J$ Effectiveness estimates just calculated, multiplied by the sum of all four source-spill baseline volumes (i.e., by the total potential benefit). For each year, the Procedure then adds together the expected $Marginal_J$ Benefits of Rule J to get yearly total marginal benefits, TM_JB_{Yr}. It next discounts each TM_JB_{Yr} by 7 percent over the assessment period to 1996. Then the Procedure sums these discounted yearly expected marginal benefits of Rule J giving the $TPVM_JB$, the TPV of the

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[13] It is important to understand that the $Overall_i$ Effectiveness Factor of Rule A joined together with Rule B cannot be calculated by simply taking the sum of the two vectors (0.40, 0.10, 0.05, 0.10) and (0.30, 0.05, 0.55, 0.0)—

$$(0.40, 0.10, 0.05, 0.10) + (0.30, 0.05, 0.55, 0.0)$$

$$= (0.40 + 0.30, 0.10 + 0.05, 0.05 + 0.55, 0.10 + 0.0) = (0.70, 0.15, 0.60, 0.10).$$

From this sum of the 2 vectors, one gets an $Overall_i$ Effectiveness Factor of

$$0.70 + (1 - 0.70) \times 0.15 + [1 - (0.70 + (1 - 0.70) \times 0.15)] \times 0.60 + \{1 - [1 - (0.70 + (1 - 0.70) \times 0.15)]\} \times 0.10$$

$$= 0.70 + 0.045 + [1 - 0.745] \times 0.60 + \{1 - [0.745 + 0.153]\} \times 0.10$$

$$= 0.70 + 0.045 + 0.153 + \{1 - [0.70 + 0.045 + 0.153]\} \times 0.10 = 0.898 + 0.0102 = 0.9082 \cong 0.91$$

Whereas the $Overall_i$ Effectiveness Factor of Rules A and B joined together was shown to be 0.86. Errors from double counting can be large. It is possible for the absolute error of the $Overall_i$ Effectiveness to be as high as 25 percent and the percentage error of $Overall_i$ Effectiveness to be as large as 33 percent if double counting is not eliminated.

i, specific source of oil spills ($i = 1$ to 4)
N, number of rules ($N = 1$ to 11)
YR, specific year ($Yr = 1996$ to 2025)

yearly expected $Marginal_J$ Benefits of Rule J. Next, the Procedure sums the discounted yearly expected costs of Rule J giving the $TPVC_J$ the Total Present Value of the yearly Costs of Rule J. Finally, the Procedure calculates the ratio of $TPVC_J$ to $TPVMB_J$ yielding the $Marginal_J$ Cost Effectiveness of Rule J.

The particular sequence in which the N rules are chosen makes no difference to the Procedure. The Procedure will yield the same results irrespective of the sequence in which the rules are entered.

F. Cost of Compliance and Enforcement

This appendix presents the methodology and assumptions used to extract rules' compliance and enforcement costs over the PRA 30-year period, 1996–2025, from the costs presented in rules' RAs. Most of the original RA cost analyses were complicated and did not specifically provide data to accommodate estimates of future costs as required for a programmatic assessment. Accordingly, the Volpe team employed deductive and mathematical processes to produce the information and costs for the PRA.

Extracted costs from the RAs are adjusted to reflect—

1) The possible use of amortized capital costs

2) The possible use of a discount rate in an RA that is different from the PRA's

3) The shorter time period of an RA versus the 30 years of the PRA

4) The number of sets of capital costs (usually capital equipment) acquired during the RA period versus the number of sets that are acquired during the PRA period

Methodology

The methodology and assumptions used to extract an individual rule's compliance and enforcement costs from its respective RA for the 30-year period of this PRA is a seven-step process.

Step 1—Make Adjustments to TPV of Capital Costs of Each RA if Necessary

Three adjustments are made to individual RA costs, if necessary—

1) If any of the capital costs in the RA were amortized (i.e., finance charges for the cost of borrowing were added to the initial capital cost and equal payments were established over a certain period of time), we must unamortize this undiscounted constant stream of costs to the value of the initial capital investment. Unamortizing capital costs creates consistency among

the rules and removes interest charges as a true cost to the rule.[14] If only the Total Present Value (TPV) of this stream is known, we convert the TPV to its annualized equivalent, then unamortize to its initial capital investment.[15]

2) If the TPV of the capital and noncapital costs of the RA was calculated using a discount rate other than the 7 percent rate used in the PRA, we recalculate the RA TPV using the 7 percent discount rate.[16]

3) If the TPV of the capital costs of the RA was calculated by discounting to a year other than the first year of costs, we adjust this TPV to be consistent with PRA methodology (the PRA discounts back to the first year, 1996, but the 1996 costs are not discounted). We calculate this adjustment by multiplying the TPV of the RA by 1.07 raised to the following exponent—

   First cost year of the RA minus the year to which the RA discounted its costs.

If the RA costs in the year to which the RA discounted were themselves discounted, then we must increase this exponent by adding 1 to it. We make this adjustment only with Rule VI.

Step 2—Separate TPV Costs of Each RA into Capital and Noncapital Costs

After costs have been adjusted in Step 1, we separate the TPV costs for each RA into the TPV of the capital costs (not recurring every year) and the TPV of the noncapital costs (recurring every year) in order to estimate costs correctly in subsequent steps.

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[14] Although finance charges from amortization and depreciation charges on equipment are real accounting costs for the buyer, benefit-cost analyses typically exclude these charges because they are not opportunity costs to society that result from the rule. Refer to U.S. Department of Transportation, *Handbook for Conducting Cost-Benefit Analysis*, August 1998.

[15] See section on deriving the annualized equivalent later in this appendix. The annualized equivalent formula becomes the unamortizing formula if the first year's cost is itself discounted and if the interest rate equals the discount rate.

[16] Suppose that the RA discounted over a period of m years using 10 percent and did not discount the costs occurring in the first year. Then, we first need to find the annualized equivalent, Y, of the TPV of the RA—

$$Y = TPV/[(1 - r^m)/1 - r)], \text{ where } r = 1/(1 + \text{RA's discount rate})$$

If the costs occurring in the first year were discounted in the RA, then the annualized equivalent would be

$$Y = TPV/[r - r^m+1)/(1 - r)]$$

Next, we would discount Y using 7 percent over the same period to get the needed TPV—

$$Y \times [(1 - R^m)/(1 - R)], \text{ where } R = 1/1.07$$

Refer to the subsection on the derivation of the annualized equivalent and Footnote 38.

Even if an RA did not explicitly separate the TPV of costs into capital and noncapital portions, we could still estimate these two portions from the information presented in the RA. As explained later in this appendix, this separation minimizes large errors in cost estimates.

Step 3—Determine if TPV Capital Costs of Each RA Must Be Prorated

We use four assumptions in determining if the TPV of the capital costs separated in Step 2 need to be prorated (adjusted upward)—

1) All capital equipment has a life of 15 years

2) One set of capital equipment is purchased in Year 1 (1996) and one set in Year 16 (2011)

3) If the RA period exceeded 15 years, then the capital costs in the RA already included the purchase of the second set of equipment, thus the TPV of the capital costs of the RA are identical to those needed for the 30-year period of the PRA

4) If the RA period did not exceed 15 years, then a second set of capital equipment costs must be included in Year 16 of the PRA, thus the TPV of the capital costs of the RA must be prorated[17]

As with the cost separation outlined in Step 2, prorating the capital costs of the RA minimizes the possibility of large errors in the estimation of PRA costs.

Step 4—Prorate TPV of Capital Costs of Each RA into TPV Needed in the PRA

We prorate the TPV of the capital costs of each RA from Step 2 into the TPV of the capital costs needed in the PRA by adjusting upwards the TPV of the capital costs of each RA. If the RA period exceeded 15 years, no proration of the TPV of the RA is required; we use the TPV of the capital costs of the RA for the TPV of the capital costs needed in the PRA and proceed to Step 5. If the RA period was less than or equal to 15 years, then the RA TPV included only one set of

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[17] For Rule I (Double Hulls), it was assumed that the life of double-hull vessels was the 30-year assessment period of the PRA. For Rule VII (Licenses, Certificates, and Mariners' Documents), one of the four constituent regulations required capital expenditures for computer hardware, software, and electronic interfacing with the National Driver Registry's database. A life cycle of only 5 years was assumed for these expenditures to reflect the accelerated rate of computer-system obsolescence and replacement. Six sets of hardware and software were assumed to be purchased during the 30-year assessment period.

capital costs, and its TPV must be prorated before it can be used in the PRA. The PRA requires two sets of capital costs—the first set in 1996 and the second set 15 years later in 2011 (three RAs have periods less than or equal to 15 years: RAs for Rules VII, X, and XI). Each set of costs needed in the PRA are equal to the TPV of the capital costs from the RA (${}_{CAP}TPV_{RA}$). The first set of PRA capital costs occurs in the first undiscounted year of 1996; however, discounting has a more noticeable effect on the second set of capital costs because these costs are discounted back to 1996, but occur in 2011.[18] The resulting prorated TPV of the capital costs of the RA, which is needed in the PRA, is thus equal to—

${}_{CAP}TPV_{RA} + [{}_{CAP}TPV_{RA}/(1.07^{15})]$, also, see **Equation (4)**

Step 5—Convert TPV of Noncapital Costs of Each RA to its Annualized Equivalent

From Step 2, we convert the TPV of the noncapital costs over the number of years in each RA into its annualized equivalent—a stream of constant yearly costs. We assume that if this cost occurred every year of the RA, then it will also occur every year of the PRA. For each RA, we use its annualized equivalent as the annual cost needed by the PRA.

This step obviates the need to further adjust the TPV of the noncapital costs of each RA even if the RA discounted its costs back to a year other than 1996. This is because the annualized equivalent depends only on the number of years over which the TPV was computed and on the discount rate used—the annualized equivalent does not depend on the specific year to which we discount when computing the corresponding TPV of capital costs. Because the annualized equivalent is invariant from the year to which the RA discounts, it greatly expedites the calculations for the PRA. A more detailed discussion of the annualized equivalent is presented in a later section of this appendix.

[18] If the RA period exceeds 15 years, there exists an alternative way of performing Step 4 that is mathematically equivalent. Since each of the two sets of capital costs for the PRA is equal to the TPV of the capital expenditures from the RA, we can convert each set's TPV into its annualized equivalent, Y, over the 15-year life of the equipment. These two streams' constant yearly costs are equal to one another in magnitude; the first set's stream is 1996–2010, and second set's is 2011–2025. These streams are discounted to 1996 to obtain the desired TPV of the capital costs for the PRA. The PRA's TPV of its capital costs is equal to $Y \times [(1 - R^{30})/(1 - R)]$, where $R = 1/1.07$.

Step 6—Express All Costs of Each RA in 1996 Constant Dollars

Because each RA was conducted at a different time prior to 1996, we must convert all TPV costs (capital costs and noncapital annualized equivalent costs) into constant 1996 dollars using the appropriate inflation factor.

Step 7—Input the Capital and Annualized Equivalent Costs of Each RA into PRAAM

The capital and annualized equivalent costs of each RA, now expressed in 1996 dollars, are input separately into the OPA 90 Programmatic Regulatory Assessment Accounting Model (PRAAM—see Chapter 5). The PRAAM discounts, to 1996 the annualized equivalent costs over the 30-year period then adds these costs back to the TPV of the capital costs to result in the TPV of all compliance and enforcement costs.

Example: Applying the Cost Methodology to Rule XI—PWS Equipment and Personnel Requirements

In the following example, we apply the seven-step methodology to Rule XI, Prince William Sound Equipment and Personnel Requirements (abbreviated in this example as PWS). An overview of the requirements of this rule is in Appendix B.

PWS Example: Step 1—Make Adjustments to TPV of Capital Costs of Each RA if Necessary

The unamortizing of capital costs for 10 of the RAs is always performed during the first step of extracting a rule's compliance and enforcement costs from its respective RA for the 30-year period of the PRA; however, for the PWS RA it is necessary to delay the unamortizing of its capital costs until a later step in the seven-step process.

It is not possible to unamortize capital costs in Step 1 for two reasons—

1) The capital cost of the Escort Response Vessels (ERVs) that make up a rotating escort service depends in a complex manner on the yearly decline in tank ship traffic in PWS.

2) The true capital cost of these rotating ERVs depends on the fraction of the total ERVs' capital cost that is attributable only to Section 5005 (the RA did not explicitly give this fraction attributable to Section 5005, but it can be derived from information in the RA).

It becomes necessary, therefore, to employ a long series of deductive steps before we can unamortize the compliance and enforcement costs of the PWS RA. Although a simpler RA could have been chosen as an example, the PWS RA was selected because its details and cost difficulties give a much broader perspective into the how RA costs were extracted and adjusted to be used in the PRA. Additionally, in the PWS example, the unamortizing of costs was the *only* step of the seven-step process that was not performed in its original order.

We initially use amortized costs for all of the capital costs used in the PWS RA; in a later step, we unamortize all of these capital costs before calculating the TPV of the capital costs for the PRA.

For the remainder of Step 1, the PWS RA used a 7 percent discount rate and no further adjustment is necessary. The unamortizing of capital costs, which occurs as part of PWS Step 4 below, automatically performs the adjustment to the TPV of the RA so that it is based on its first year of costs; thus, no further adjustment is necessary.

PWS Example: Step 2—Separate TPV Costs of Each RA into Capital and Noncapital Costs

The PWS RA, like most of the other RAs, did not explicitly state or separate the TPV of its costs into capital and noncapital components. The RA identified four capital costs (all amortized) over the 10-year period of the RA (1993–2002)—

1) On-board equipment for two prepositioned barges—the undiscounted capital cost is an estimated $11,898,401.[19]

2) Boom and miscellaneous equipment required at the hatcheries and Community Response Centers—the undiscounted capital cost of acquiring and prepositioning booms is an estimated $10,582,000.[20] This cost does not account for booms on the barges and ERVs.[21]

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[19] Because of the large number of computations in the cost methodology as well as rounding errors when discounting PRA costs over 30 years, all costs and computations presented here are given exactly (no rounding).

[20] The RA reported that the total cost of boom and miscellaneous equipment is $22,582,000 over the 10-year period. An estimated $12,000,000 is the maintenance cost over the 10-year period. Therefore, an estimated $10,582,000 is the capital cost. U.S. Coast Guard, *Equipment and Personnel Requirements under Vessel Response Plans for Tank Vessels Operating in Prince William Sound*, January 1993, p. 16.

[21] *Ibid.*, Appendix 3B, p. 11.

3) On-board equipment for a single ERV prepositioned at Port Etches on Hinchinbrook Island with a barge—the undiscounted capital cost is an estimated $1,227,020.[22]

4) On-board equipment for three ERVs making up a rotating escort service *not* at Port Etches (henceforth "rotating ERVs")—the undiscounted capital cost is estimated at $1,663,956.[23]

The PWS RA computed costs in constant 1990 dollars, and it discounted all its costs back to 1992 using a discount rate of 7 percent. The sum of the four capital costs is $25,371,377 for the period 1993–2002. The capital costs *excluding* the capital cost of the rotating ERVs are $23,707,421. The capital cost of the rotating ERVs for this period is $1,663,956. The corresponding RA TPVs for these costs are $17,819,794, $16,651,101, and $1,168,693, respectively.

The PWS RA reported $232,035,798 for the rule's undiscounted compliance and enforcement costs over the 10-year period 1993–2002.[24] The TPV of these costs was $163,979,882 using the PWS RA discount rate of 7 percent. The TPV of the noncapital costs of the RA is $146,160,088 ($163,979,882 - $17,819,794). Noncapital costs include training and drilling residents and fish

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[22] *Ibid.*, Appendix 3B, p. 12. The total cost is $41,847,020; $39,420,000 of this is a lease cost and $1,200,000 is labor cost over the 10-year period. The remaining cost is the capital cost.

[23] Each of the three rotating ERVs would have required the same undiscounted capital cost over the 10-year assessment period of the RA as the Port Etches ERV ($1,227,020); however, the true cost is considerably smaller. There are two reasons for the smaller cost per rotating ERV. First, the yearly decrease in oil production on Alaska's North Slope results in a corresponding yearly decrease in laden tank ship traffic in PWS. Based on a 1991 sample of tank ship traffic, the RA computed that, on average, 1 ERV undertook 225 annual escorts. In 1993, 670 laden tank ship trips occurred, so three ERVs were needed. The 1999 traffic projection was below 450, requiring only 2 ERVs thereafter. The second reason for the smaller cost per rotating ERV is that only a fraction of the rotating ERVs' costs are attributable to Rule XI (Section 5005 of OPA 90); some of the costs are attributable to Section 4116(c) of OPA 90, which is not part of Rule XI.

The RA does not explicitly give the fraction attributable to Rule XI, but provides enough information to allow us to derive an estimate. The capital equipment costs for the three rotating ERVs outfitted in 1993 (3 × $1,227,020 = $3,681,060) over the 10-year period are added to the noncapital costs of the 26 = 3+3+3+3+3+3+2+2+2+2 rotating ERVs [26 × ($4,184,702 - $122,702) = $105,612,000] over the 10-year period. This sum ($109,293,060) represents what the total rotating ERVs' costs would have been if 100 percent of the costs had been attributable to Rule XI. This sum is divided into the actual smaller cost of the three rotating ERVs used in the RA, $91,250,961 - $41,847,020 = $49,403,941. (The $91,250,961 is the cost of all ERVs both rotating and not rotating over the 10-year period; the $41,847,020 is the cost of the non-rotating ERV over the 10-year period). The result of the division $49,403,941/$109,293,060 is 0.45203182.

In the first cost year of the RA period (1993), three ERVs are needed, so three corresponding units of on-board equipment are purchased. These capital costs are "sunk" costs and cannot be reduced even though the number of required rotating ERVs decreases to two in 1999 (noncapital costs, such as leasing and labor, however, are reduced). Therefore, the undiscounted capital cost of the rotating ERVs over the 10-year period is: 3 ERVs × $122,702 per ERV per year × 10 years × 0.45203182 = $1,663,956.

[24] U.S. Coast Guard, *op. cit.*, Exhibit 5-5, p. 14.

hatchery employees in PWS. The RA reported that the costs for training and drilling would occur at a constant level each year.[25]

The discounted capital costs represent a relatively low percentage (10.9 percent, $17,819,794/ $163,979,882) of the total discounted costs over the 10-year period. This low percentage reflects the method of acquisition for the two prepositioned barges and the additional ERV. These vessels are leased on a yearly basis rather than purchased.

PWS Example Step 3—Determine if TPV of Capital Costs of Each RA Must Be Prorated

Because the assessment period of the PWS RA did not exceed 15 years, its capital costs would not have included the purchase of a second set of capital equipment. Therefore, the RA's TPV of the amortized capital costs must be prorated (i.e., adjusted upwards).

The RA's TPV of the amortized capital costs for the rotating ERVs is considerably more difficult to prorate than the RA's TPV of the capital costs not associated with the rotating ERVs. The longer period of the PRA provides an opportunity to reduce the rotating ERVs' capital cost in 2011, when only one ERV will be needed; the capital cost for the second 15-year period (2011–2025) is, therefore, smaller. Because of the decrease in the rotating ERVs' capital cost and the complexity involved, the rotating ERVs' costs were estimated in a separate spreadsheet model.

PWS Example Step 4—Prorate TPV of Capital Costs of Each RA into TPV Needed in the PRA

The PWS RA amortized all four of the capital costs over a 10-year period at an interest rate of 10 percent. The RA assumed that capital equipment was acquired in 1992 but that the ten equal payments that included both interest and principle did not begin until 1993. This resulted in a stream of constant yearly capital costs (e.g., the ERV at Port Etches had a yearly equipment cost of $122,702 ($1,227,020/10). Following standard benefit-cost analysis practice, the PRA does not count finance charges (interest charges incurred when borrowing money) as a true cost to a rule; therefore, we must unamortize the capital costs.

First, the TPV of the amortized capital costs that are not associated with the rotating ERV, $16,651,101, are unamortized. Then, this TPV will be converted into the TPV needed in the PRA. However, we cannot apply the unamortizing formula directly to this TPV—we must first

[25] *Ibid.*, Section 5.4, p. 18.

convert the TPV to its annualized equivalent, Y_1, i.e., to an undiscounted constant stream of amortized costs—

> $Y_1 = (\$16,651,101)/[(R - R^{10+1})/(1 - R)] = \$2,730,742$ each year 1993–2002 in 1990 dollars
>
> where $R = 1/1.07 = 0.93457944$

In the formula for the annualized equivalent, the extra 1 in the exponent of R, "10 + 1," reflects that the PWS RA discounted its first-year costs when calculating TPV.

We then unamortize this constant stream, which results in a one-time initial capital investment—

> $\$2,730,742 \times [(r - r^{10+1})/(1 - r)] = \$14,567,184$ in 1990 dollars
>
> where $r = 1/1.10 = 0.909090909$

The finance charge during the 10-year period of the RA for the capital costs not associated with the rotating ERVs is \$2,083,817 (\$16,651,101 - \$14,567,184).

We now convert the unamortized TPV of this capital cost of \$14,567,184 into the TPV needed in the PRA. We use the alternate method of conversion (Footnote 38). This method first converts the TPV of the RA, \$14,567,184 into an annualized equivalent spread over 15 years—

> $Y_2 = \$14,567,184/[(1 - R^{15})/(1 - R)] = \$1,484,765$ for each year of the 15-year life of the capital equipment (1996–2010)
>
> where $R = 1/1.07 = 0.93457944$

The PRA requires a second set of capital equipment to be bought in Year 16 (2011), and this second set will also cost \$14,567,184, or \$1,484,765 for each year of the 15-year life of the capital equipment (2011–2025). These two 15-year streams makeup a 30-year constant stream of capital costs of \$1,484,765 (1996–2025). Since this constant stream is based on an annualized equivalent, the constant stream of \$1,484,765 is undiscounted.

The TPV of unamortized capital costs (excluding the rotating ERV capital costs) over the 30-year period is—

$$\sum_{i=1}^{30} \$1,494,954/(1 + 0.07)^{i-1} = \$1,494,954 \times [(1 - R^{30})/(1 - R)] = \$19,847,002$$

The unamortized TPV of the capital costs for the rotating ERV is $1,145,954 from the spreadsheet model. The combined TPV for all capital costs is $20,992,956 ($19,847,002 + $1,145,954).

PWS Example: Step 5—Convert TPV of Noncapital Costs of Each RA to its Annualized Equivalent

As in Step 4, the decrease in the number of required rotating ERVs also affects TPV of the noncapital costs in a complex manner. We cannot directly use the noncapital portion of the rotating ERVs from the RA because the decrease in the required number of rotating ERVs as reported in the RA begins and ends in different years from the PRA's decrease. As with the rotating ERVs' capital cost, therefore, the noncapital cost associated with rotating ERVs over the 30-year PRA period is calculated in a separate spreadsheet model.

As previously calculated in Step 2, the TPV of all noncapital costs for the RA was $146,160,088 for the period 1993–2002. From the separate spreadsheet model, the TPV of noncapital costs of the RA for the rotating ERVs is $34,544,842 for the period 1993–2002. The difference, $111,615,246, is the TPV of the noncapital costs not associated with rotating ERVs for the period 1993–2002. This has an annualized equivalent, Y_3, of—

$$\$111{,}615{,}246/[(1 - R^{10+1})/(1 - R)] = \$15{,}891{,}500 \text{ in 1990 dollars}$$

From the spreadsheet model, the rotating ERVs have a TPV of noncapital costs of $45,955,939 in 1990 dollars over the period 1996–2025. This has an annualized equivalent, Y_4, of—

$$\$45{,}955{,}939/[(1 - R^{30})/(1 - R)] = \$3{,}461{,}144 \text{ in 1990 dollars}$$

We add these two annualized equivalents together to calculate the total constant recurring noncapital cost for the PRA, $19,352,644, in 1990 dollars.[26] Although the rotating ERV noncapital costs are not constant recurring costs, we can express them this way through the annualized equivalent formula.

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[26] The RA found costs incurred by the Coast Guard to monitor and enforce compliance with regulations issued under Rule XI to be negligible. Also, costs of periodic certifications of prepositioned equipment were assumed to be negligible.

PWS Example: Step 6—Express All Costs of Each RA in 1996 Constant Dollars

We convert the costs expressed in 1990 dollars into 1996 dollars using an inflation factor of 1.1708 (see Chapter 8). The TPV of the unamortized capital cost in 1996 dollars over the 30-year period is $24,578,553 ($20,992,956 × 1.1708). Likewise, the constant recurring cost is $22,658,075 ($19,352,644 × 1.1708). These two costs are the inputs needed for the OPA 90 PRAAM.

The TPV of all capital and noncapital costs over 1996–2025 is

$$\$324{,}803{,}281 = \$24{,}578{,}553 + (\$22{,}658{,}075) \times [(1 - R^{30})/(1 - R)] \text{ in 1996 dollars}$$

PWS Example: Step 7—Input the Capital and Annualized Equivalent Costs of Each RA into PRAAM

The capital and annualized equivalent costs of each RA, now expressed in 1996 dollars, are input separately into PRAAM. PRAAM discounts, to 1996 the annualized equivalent costs over the 30-year period then adds these costs back to the TPV of the capital costs to result in the TPV of all compliance and enforcement costs.

Summary of RA inputs to PRAAM

Table F-1 presents a summary of the parameters and costs from the RAs that are needed for the OPA 90 PRAAM.

Table F-1
Summary of RA Cost Parameters for PRAAM

PRA Rule	Short Title (Constant Year $)	RA Time Period (Inclusive)	RA Discount Rate (%)	RA TPV of Capital Costs	RA TPV of Annual Noncapital Costs	TPV of Capital Costs Adjusted for PRA Period and Discounted at 7%[27] (RA Year $)	Constant Annual Noncapital Cost Discounted at 7% (RA Year $)
I	Double Hulls (1991)	1991–2015	10%	$2,678,672,209[28]	$807,327,791	$3,345,229,320	$80,856,133
II	Deck Spill Control (1993)	1993–2015	7	1,274,296	9,725,704	1,274,296	806,630
III	Source Spill Control and Containment (1993)	1993–2015	7	189,115,007	10,884,993	189,115,007	982,241
IV	Lightering of Single Hull Vessels (1994)	1995–2014[29]	10[30]	6,000,000	0	7,211,341	0
V	Overfill Devices (1991)	199 2–2006	7	108,050,000[31]	13,853,137	141,933,606	1,521,000
VI	Operational Measures of Single Hull Vessels (1996)	1996–2014	7	33,647,654	125,919,405	33,647,654	11,386,058
VII	Licenses, Certificates, and Mariners' Documents (1993)						
1)	*5-Year Term Validity for Certification of Registry*	None given[32]	None used	0	Not given	0	5,019,120
2)	*Chemical Testing during First Time Licensing*	None given	None used	0	Not given	0	439,000
3)	*National Driver Register and Criminal Record Access*	None given	None used	20,000	Not given	60,529[33]	181,336
4)	*Suspension and Revocation of Licenses and Certificates*	None given	None used	0	Not given	0	0
VIII	Financial Responsibility (1994)	None given	None used	0	Not given	0	360,500,000[34]
IX	Vessel Response Plans (1992)	1992–2015	7	346,068,774[35]	2,414,931,226	346,068,774	196,780,831
X	Facility Response Plans (1992)	1992–2001	10	17,988,000[36]	69,244,383	24,507,679	10,244,731
XI	PWS Equipment & Personnel Requirements (1990)	1993–2002	7	17,819,794	146,160,088	20,992,956[37]	19,312,644

[27] Assumes capital equipment has 15-year life and a set bought in Year 1 and Year 16. If RA period > 15 years, no capital adjustment. If RA period ≤ 15 years, need to adjust. Last two columns of Table F-1 correspond to first two columns of Table 8-1.

[28] RA costs used in reference case except Rules I and VIII. TPVs at 10 percent must be converted to TPVs at 7 percent; capital versus noncapital is split from updated Double Hull cost report.

[29] RA did not give first year of period. Since *FR* 8/5/94, p. 40186, states rule effective 11/94 and since RA written 5/94, we assume period begins 1995.

[30] *FR* 10/22/93, p. 54877. Rule originally was part of larger rule that used 10 percent; lightering requirements later made into its own rule.

[31] Using average from cost range of *FR*, 10/21/94, p. 53289.

[32] RA used a general 5-year period by assuming one-fifth of the total pool of applicants renew each year.

[33] Assumes computer equipment becomes obsolete in 5 years. TPV of capital costs is adjusted to reflect that 5 additional sets of capital equipment must be bought for 2001–2025.

[34] RA gave three different cost scenarios; Volpe Team took the average of the second and third scenarios and did not use the P&I Club Insurance scenario.

[35] RA, pp. 136–137. RA period is 24 years and capital equipment lasts 15 years. We assume RA TPV of capital cost already has the two sets of capital equipment needed in PRA.

[36] RA, pp. 3–16 for six categorizes of facilities with capital costs for boom. As is the case for vessels (Rule IX), facilities rent or contract out most equipment and response capability.

[37] From RA, Appendix 3B, pp. 11–15, $17,819,794 is the TPV of capital costs and is deduced. Barges and ERVs are rented. RA amortized capital cost at 10 percent; OMB excludes amortization and interest charges, so costs must be unamortized. The decreasing number of yearly tank ship trips drives ERV costs.

Derivation of Annualized Equivalent Formula

To derive the formula for the annualized equivalent (where we do not discount the first year), let Y be the annualized equivalent we seek. Then—

$$TPV = Y/1 + Y/1.07 + Y/(1.07)^2 + Y/(1.07)^3 + \ldots\ldots\ldots\ldots + Y/(1.07)^{N-2} + Y/(1.07)^{N-1}$$

$$= Y[1 + 1/1.07 + 1/(1.07)^2 + 1/(1.07)^3 + \ldots\ldots\ldots\ldots + 1/(1.07)^{N-2} + 1/(1.07)^{N-1}]$$

$$\text{Thus, } Y = TPV/[1 + 1/1.07 + 1/(1.07)^2 + 1/(1.07)^3 + \ldots\ldots\ldots + 1/(1.07)^{N-2} + 1/(1.07)^{N-1}]$$

$$\text{Let } 1/1.07 = 0.934579439 = R$$

$$\text{Then, } Y = TPV/(1 + R + R^2 + R^3 + \ldots\ldots\ldots\ldots + R^{N-2} + R^{N-1})$$

Let the sum of the first N terms of the geometric series $1 + R + R^2 + R^3 + \ldots + R^{N-2} + R^{N-1}$ be S.

Equation (1) $S = 1 + R + R^2 + R^3 + \ldots\ldots\ldots + R^{N-2} + R^{N-1}$

Then R times this sum S is—

Equation (2) $R \times S = R + R^2 + R^3 + R^4 + \ldots\ldots\ldots\ldots + R^{N-1} + R^N$

Subtract **Equation (2)** from **Equation (1)**—

Equation (3a) $S - (R \times S) = 1 + 0 + 0 + 0 + \ldots\ldots\ldots\ldots + 0 + 0 - R^N = 1 - R^N = S \times (1 - R)$

Divide **Equation (3a)** by (1 - R)—

Equation (3b) $(1 - R^N)/(1 - R) = S \times (1 - R)/(1 - R) = S$

So Y, the annualized equivalent for the TPV over N years, is—

$$Y = TPV/[1 + R + R^2 + R^3 + \ldots\ldots\ldots\ldots + R^{N-2} + R^{N-1}] = TPV/S = TPV/[(1 - R^N)/(1 - R)]$$

where $R = 1/(1 + \text{the discount rate})$

If the first cost year were discounted, then the formula for the annualized equivalent, Y, would become—

$$Y = TPV/[R - R^{N+1})/(1 - R)]$$

Separation of RA Costs to Minimize Errors

After detailed analyses of the RAs for the 11 core group rules, we determined that lumping all costs together (i.e., not separating the costs into capital and noncapital components) produced an unacceptable level of error in our cost estimates for the OPA 90 PRA.

The first error would occur if capital and noncapital costs were not separated, and we mistakenly assumed that an unrecognized capital cost were a noncapital cost that would, therefore, occur every year of the 30-year PRA period. Thus, prorating from the shorter RA period to the longer PRA period would result in a TPV of all costs that is overestimated.

Similarly, the second error would occur if capital and noncapital costs were not separated, and we mistakenly assumed that an unrecognized noncapital cost were a capital cost that would, therefore, recur once every 15 years of the 30-year PRA period. Thus, prorating from the shorter RA period to the longer PRA period would result in a TPV of all costs that is underestimated.

Proration Errors

A proration error could happen in several ways. For example, suppose that the TPV of the RA were computed over the 10-year period 1993–2002, using a 7 percent discount rate, and the TPV of the PRA period is the 30-year period, 1996–2025, also at 7 percent (we assume that both did not discount costs in the first year). Then, we might incorrectly infer that the TPV of the PRA could be derived using a simple linear decrease of 3 to 1, i.e., [(30/10) × (TPV of the RA)]. This would be incorrect because the 11th through 30th years of the PRA would be discounted more. The ratio needed to convert the TPV of the RA to the TPV of the PRA and that correctly accounts for the greater effect of discounting in later years of the PRA is—

$$[(1 - R^{30})/(1 - R)]/[(1 - R^{10})/(1 - R)] = (1 - R^{30})/(1 - R^{10}), \text{ where } R = 1/1.07$$

This ratio is (13.278/7.515) = 1.767[38]

[38] The more general case where the RA used a discount rate not equal to the PRA's 7 percent over a time period of M years (not equal to the PRA's N = 30) will require a slightly more complicated proration. The correct ratio to convert the TPV of the RA to the TPV of the PRA in this case would be—

$$[(1 - R^{30})/(1 - R)]/[(1 - r^{M})/(1 - r)], \text{ where } r = 1/(1 + \text{the discount rate of the RA}) \text{ and } R = 1/1.07$$

A proration error could also occur if we do not choose the correct number of sets of capital expenditures or choose the correct number of sets but use the wrong annualized equivalent when converting to the PRA's corresponding costs. For example, suppose the TPV of the capital portion of the costs of an RA over a period of 10 years, 1993–2002, using a 7 percent discount rate, were $18,000,000. We might think that this would also be the TPV of the capital portion of the costs over the 30-year period of the PRA. Recall that in our methodology, however, that we assumed that if the RA period did not exceed 15 years, then a second set of capital equipment would be purchased in Year 16 of the PRA (2011); thus, the TPV of the capital costs of the PRA would need to be prorated.

The TPV over the 30-year period of the PRA would not be 2 × $18,000,000 = $36,000,000. This is because the two $18,000,000 costs occur only in Year 1 and Year 16 of the PRA, and are equivalent to an undiscounted stream of costs—

$$\$18{,}000{,}000/[(1 - R^{15})/(1 - R)] = \$1{,}847{,}012 \text{ from 1996–2010}$$

Each constant stream is the annualized equivalent of the $18,000,000 capital cost over the equipment's 15-year life. To find the TPV of this stream of capital costs over the 30-year period, we compute—

$$\sum_{i=1}^{30} \$1{,}847{,}012/(1 + 0.07)^{i-1} = \$1{,}847{,}012 \times [(1 - R^{30})/(1 - R)] = \$24{,}524{,}023$$

that is equivalent to—

For example, if the RA used a discount rate of 10 percent over a time period of 19 years, the correct proration ratio would be—

$$[(1 - R^{30})/(1 - R)]/[(1 - r^{19})/(1 - r)]$$

The ratio with r = 1/1.10 = 0.90909091 and with M = 19 would be (13.278/9.201) = 1.443.

Equation (4): $\$18{,}000{,}000/1 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0$

$+ \$18{,}000{,}000/(1.07)^{15} + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 + 0 =$

$24,524,023

In **Equation (4)**, we have used the two estimates of total capital investment rather than two equal streams of costs over the 30-year period. That the TPV of the RA began in 1993 versus 1996 for the RA is irrelevant to the calculation because both the RA and the PRA discount to their first cost year. However, if the RA in computing its TPV had discounted its first year (which the PRA does not do), then the RA is discounting to 1992, and that is relevant. In that case, the TPV of the RA must first be adjusted by multiplying its TPV by 1.07 raised to an exponent of—

[1st cost year of the RA minus the year to which the RA was discounted] = 1993-1992 = 1

Annualized Equivalent Does Not Depend on Year to which its Corresponding TPV Is Discounted

Previously, we noted that an annualized equivalent does not depend on the specific year to which we discount when calculating the corresponding TPV. This allows us to not be concerned with adjusting the noncapital TPV of the RA to reflect that the noncapital TPV of the RA was discounted to a year other than 1996. For example—

Let $100 million be the noncapital constant yearly undiscounted cost over the period 1993–2002. The TPV of this cost discounted to 1992, ${}^{1992}TPV^{1993\text{–}2002}$, would be—

$\$100\text{ mil}/(1.07)^1 + \$100\text{ mil}/(1.07)^2 + \ldots\ldots + \$100\text{ mil}/(1.07)^{10} =$

$\$100\text{ mil} \times (R - R^{11})/(1 - R) = \$702{,}358{,}154$

where $R = 1/1.07$

The annualized equivalent of the ${}^{1992}TPV^{1993\text{–}2002}$ would be—

$\$702{,}358{,}154/[(R - R^{11})/(1 - R)] = \$100\text{ mil} \times (R - R^{11})/(1 - R)/[(R - R^{11})/(1 - R)] =$

$\$100\text{ mil} \times 1 = \$100\text{ million}$

The TPV of this cost using discounting to 1996, ${}^{1992}TPV^{1993-2002}$, would be—

$$\$100 \text{ mil}(1.07)^3 + \$100 \text{ mil}(1.07)^2 + \$100 \text{ mil}(1.07)^1 + \$100 \text{ mil}(1.07)^0 + \$100 \text{ mil}/(1.07)^1 + \ldots\ldots\ldots + \$100 \text{ mil}/(1.07)^6 =$$

$$\$100 \text{ mil}[(1/R^3 - R^6)/(1 - R)] = \$854{,}014{,}043$$

The annualized equivalent of ${}^{1996}TPV^{1993-2002}$ would be—

$$\$854{,}014{,}043/[(1/R^3 - R^6)/(1 - R)] =$$

$$\$100 \text{ mil}[(1/R^3 - R^6)/(1 - R)]/[(1/R^3 - R^6)/(1 - R)] = \$100 \text{ mil} \times 1 = \$100 \text{ million}$$

Whenever the year to which we discount the TPV is changed, any resulting change in the TPV is exactly compensated by the corresponding change in the denominator used in computing the corresponding annualized equivalent. Of course, we must exercise care in choosing the denominator. In our example, changing the year for discounting from 1992 to 1996 changes the TPV from $702,358,154 to $854,014,043, a ratio of 1.203109892 ($854,014,043/$702,358,154). The denominator that we use to compute the annualized equivalent has, however, also changed from 7.02358154 to 8.544014043, which is exactly the same ratio (1.203109892 = 8.544014043/ 7.02358154), which cancels out the first change in TPV and gives identical annualized equivalents.

G. COST OF REMOVING SPILLED OIL

The increase in recovery costs due to the implementation of any chosen subset of the OPA 90 rules (possibly all 11 or possibly just 1) must be determined.[39] This involves a four-step process—

1) Compute the yearly marginal[40] effectiveness of the 4th order factors of the subset of rules chosen[41]

2) Multiply these yearly marginal 4th order effectiveness estimates by the corresponding yearly baseline spillages in gallons to get the yearly marginal benefit

3) Multiply these yearly marginal gallons by $5, the recovery cost of a gallon of oil[42]

4) Discount the yearly results from Step 3

The above four-step process must be done separately for each of the four spill sources—tankers underway, barges underway, lightering operations, and facilities.

For the subset of N rules chosen, the Procedure (see Appendix E) first calculates each rule's overall effectiveness [1st through 4th orders] factor for each "spill-source-per-year" combination. This represents a rule's overall effectiveness when all four of its effectiveness factors are included. Then, the Procedure calculates a grand overall effectiveness [1st through 4th orders] factor from the N overall effectiveness [1st through 4th orders] factors.

Similarly, for the subset of N rules chosen, the Procedure will also calculate a grand overall effectiveness [1st through 3rd orders] factor for each spill-source-per-year combination. The difference between the grand overall effectiveness [1st through 4th orders] factor and the grand

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[39] In addition, since the calculation of the quantity (marginal cost of Rule A)/(marginal benefit of Rule A) will be needed, the marginal recovery cost of Rule A will need to be calculated. This is defined as the recovery cost of all of the rules minus the recovery cost of all of the rules when Rule A is excluded.

[40] Although the marginal effectiveness of the 4th order factors of the subset of rules is defined in an analogous way to the marginal effectiveness of a single rule, the two entities are very different and should not be confused.

[41] Except for cases when the subset of rules chosen for consideration does not include Rules I, IV, and VI (in which case the marginal overall 4th order effectiveness of the subset of chosen rules will be zero) the subset's marginal overall 4th order effectiveness will be different every year since the effectiveness factors of Rules I, IV, and VI will vary by year due to the phasing in of double hulls or to the phasing out of single hulls.

[42] Since there is no good source of data on actual cost experience for containment and removal of oil from the water, this estimate should be considered an assumption. It is based upon a review of "The Financial Costs of Oil Spills" by Dagmar Schemidt, Ph.D., *Oil Spill Intelligence Report*, Cutter Information Corporation, 1994.

overall effectiveness [1st through 3rd orders] factor is the marginal effectiveness of the 4th order factors of the subset of rules.

It is important to note that the grand overall effectiveness [1st through 4th orders] factor of the subset of N rules includes the non-OPA 90 recovery rate in its calculation.

Example

Let us calculate the recovery cost of the subset of rules consisting of all 11 of the rules. We will calculate the recovery cost for just one of the four spill sources—tankers underway—and for just a single year—1996.[43]

Suppose one of the 11 rules, Rule A for tankers underway, has the following effectiveness factors: 1st order, 0.20; 2nd order, 0.10; 3rd order 0.05; 4th order, 0.15. Recall that the non-OPA 90 recovery rate is 0.10 (see Chapter 6). An adjustment has to be made to the 4th order effectiveness factor of Rule A to reflect the already existing non-OPA 90 recovery rate—

$$0.15 \times (1 - 0.10) = 0.135$$

The overall effectiveness [1st through 4th orders] factor resulting from passing all four factors (0.20, 0.10, 0.05, 0.135) through the Procedure to eliminate double counting is computed—

$$0.20 + (1 - 0.20) \times 0.10 + (1 - (0.20 + 0.08)) \times 0.05 + (1 - (0.28 + 0.036)) \times 0.135 =$$

$$0.20 + 0.08 + 0.036 + 0.09234 = 0.40834$$

To make this example more realistic, suppose that Rule A's overall effectiveness does not apply to 100 percent of the baseline spillage for tankers underway. Assume that for the years 1996–2014, Rule A applies only to single-hull tankers and that in 1996 single-hull tankers make up 86.1 percent of the total baseline spillage of all tankers underway. Then, the overall effectiveness [1st through 4th orders], 0.40834, of Rule A must be adjusted by multiplying it by 0.861.[44] Therefore, the adjusted overall effectiveness [1st through 4th orders] of Rule A becomes—

[43] The recovery cost for the other years would be similarly computed; each year's recovery cost for tank ships underway would be discounted by 7 percent back to 1996 and then added together to get the TPV of the recovery cost for tank ships underway over the period 1996–2025. The TPV of the recovery cost for each of the other three spill sources would be calculated in an analogous fashion. Then, the TPV of the recovery cost for each of the four spill sources would be added together to get the grand TPV of the recovery cost.

[44] This adjustment must be made to the rule's overall effectiveness; if the adjustment were to be made to the baseline spillage, then required multiple applications of the Procedure would not be possible.

$$0.40834 \times 0.8610 = 0.35158$$

The above steps used to compute the overall effectiveness [1st through 4th orders] factor of Rule A for tankers underway are repeated for each of the other 10 rules. Then the resulting 11 separate overall effectiveness [1st through 4th orders] factors are themselves passed through the Procedure, this time to eliminate any double counting among the 11 rules. The resulting grand overall effectiveness [1st through 4th orders] factor of the 11 rules in this example is equal to 0.61667.

The grand overall effectiveness [1st through 3rd orders] of the 11 rules is next computed for tankers underway. It is calculated exactly as the grand overall effectiveness [1st through 4th orders] factor except all 4th order factors are first zeroed-out. In this example, the grand overall effectiveness [1st through 3rd orders] factor is equal to 0.58058.

The marginal effectiveness of the 4th order factors of the 11 rules for tank ships underway is equal to the grand overall effectiveness [1st through 4th orders] factor of the 11 rules minus the grand overall effectiveness [1st through 3rd orders] factor of the 11 rules, which is 0.61667 - 0.58058 = 0.03609.

This marginal effectiveness of the 4th order factors of the 11 rules for tankers underway, 0.03609, would be multiplied by the baseline spillage for tankers in 1996, which is 2,258,873 gallons (see Appendix D). This yields—

$$0.03609 \times 2{,}258{,}873 \text{ gallons} = 81{,}523 \text{ gallons}$$

At $5 per gallon recovered, this results in a recovery cost of $407,614 (undiscounted) in 1996 for a subset consisting of all 11 of the rules considered together as a single entity. The same process would be followed for each year subsequent to 1996; each year's recovery cost would be discounted by 7 percent to 1996, and each discounted result (1996–2025) would be added together to get the TPV of the recovery cost for tankers underway.

H. AVOIDED COST

In order to estimate the expected avoided costs of the core group of OPA 90 rules, we need three pieces of information—

1) Estimated annual incidents that will occur without OPA 90 (i.e., an incident baseline). Estimated annual incidents cover four categories—

   a) Vessel casualties (tankers and barges)

   b) Human fatalities from vessel casualties

   c) Human injuries from vessel casualties

   d) Number of barrels of oil not spilled or spilled and removed (BNSR). These BNSR were estimated in the benefits section of the PRA and were valued at $20/BNSR. They are not discussed further in this appendix.

2) Estimated unit cost per incident

3) First order effectiveness factors for each of the 11 rules in the core group, as estimated by Expert Panel B

Annual Vessel Casualties, Fatalities, and Injuries

The estimated annual number of vessel casualties (tankers and barges), human fatalities, and human injuries were derived from Marine Safety Information System (MSIS) data, 1981–1990, obtained from the Coast Guard's Data Administration Division (G-MRI-1). The summary of the analysis for these data is presented in Table H-1.[45] Although tankers are involved in less than half as many vessel casualties as barges, the number of fatalities and injuries for tankers is roughly six times the number for barges.

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[45] The number of people "missing at sea" is included in the annual number of fatalities. Fatalities and injuries that were unrelated to the vessel casualty were not included in the annual numbers.

Table H-1
Vessel Casualties, Fatalities, and Injuries, 1981–1990, by Tankers and Barges

Year	Tankers			Barges		
	Casualties	Fatalities	Injuries	Casualties	Fatalities	Injuries
1981	253	1	2	674	0	0
1982	200	13	11	556	0	0
1983	215	1	4	615	0	4
1984	188	9	15	539	3	3
1985	187	0	18	487	3	6
1986	255	5	21	546	0	1
1987	228	3	17	543	0	1
1988	255	1	14	622	0	1
1989	283	3	14	476	0	2
1990	268	6	14	565	0	5
Totals	2,332	42	130	5,623	6	23
Annual Average	**233.2**	**4.2**	**13.0**	**562.3**	**0.6**	**2.3**

Unit Costs of Vessel Casualties, Fatalities, and Injuries

Vessel Casualties

Vessel casualties have two estimated unit costs—

1) Unit vessel damage—costs of repairing damage to a vessel, other costs incurred prior to repair (e.g., refloating, drydocking, cleaning fuel and cargo tanks)

2) Unit vessel downtime—costs to society resulting from a casualty (e.g., crew dismissal, vessel operation, capital charges, exceptional port services, crew salaries, stores, supplies, maintenance, management, insurance)

From the 1991 USCG *Port Needs Study* (PNS), the estimated vessel casualty unit cost for vessel damage was $300,602 for tankers and $108,085 for barges ($1990).[46] Adjusted for inflation to $1996, these costs are $351,945 and $126,546, respectively. These costs were calculated by taking a weighted average of unit vessel damage costs for light, moderate, and severe damage in casualty incidents. The weights are the relative frequency of the severity of damage: light = 0.05512, moderate = 0.16760, severe = 0.77727.[47]

[46] U.S. Coast Guard. *Port Needs Study* (Volume I). August 1991, based on information found in "Developing Estimates of Costs Associated with Oil and Hazardous Chemical Spills and Costs of Idle Resources during Vessel Repairs," Eastern Research Group, Inc., November 1990.

[47] *Ibid.*

From PNS, the estimated vessel casualty unit cost for vessel downtime was $320,442 for tankers and $22,769 for barges ($1990). Adjusted for inflation to $1996, these costs are $375,173 and $26,658, respectively. These costs were also calculated by taking a weighted average of unit vessel damage costs for light, moderate, and severe damage in casualty incidents.

These two unit costs are combined to estimate total unit costs—$727,118 for tankers and $153,204 for barges. Because not all vessel casualties result in vessel damage or vessel downtime, each vessel casualty is multiplied by the probability of damage given a vessel casualty has occurred. These conditional probabilities are 0.3659 for tankers and 0.4497 for barges.

The annual average cost for tanker-underway casualties, 1981–1990, is—

232.2 casualties × $727,118/casualty × 0.3659 = $62,043,437

The annual average cost for barge-underway casualties, 1981–1990, is—

562.3 casualties × $153,204/casualty × 0.4497 = $38,740,130

Fatalities

Using DOT's research-derived estimate of society's willingness to pay to avoid a transportation-related fatality, $2.7 million, we calculate an annual average cost from 1981–1990 of—

4.2 fatalities × $2.7 million/fatality = $11,344,000 for tankers underway ($1996), and

0.6 fatalities × $2.7 million/fatality = $1,620,000 for barges underway ($1996).

Injuries

The PNS cost of a human injury was based on a review of 227 injuries that occurred as a result of vessel casualties. The PNS estimate included costs for pain and suffering, compensation, hospital care, medical treatment and rehabilitation, lost productivity and wages, legal fees and court costs, employer costs, and insurance administration. Based on a weighted average of the PNS costs of different types of injuries and their frequencies, the estimated unit cost of an injury was $275,249 ($1990). Using the Consumer Price Index for medical costs, this cost is inflated to $413,023 ($1996).[48] The annual average costs for injuries, 1981–1990, are—

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[48] The Consumer Price Index is used rather than GNP Price Deflators because a specific cost, medical costs, is examined.

13.0 injuries × $413,023/injury = $5,369,299 for tankers underway ($1996), and

2.3 injuries × $413,023/injury = $949,953 for barges underway ($1996).

Table H-2 presents a summary of the costs for vessel casualties, fatalities, and injuries, 1981–1990.

Table H-2
Average Annual Costs, 1981–1990, for Vessel Casualties, Fatalities, and Injuries, by Tankers and Barges ($1996)

Type of Cost	Tankers	Barges	Total
Vessel Casualties	$62,043,437	$38,740,130	$100,783,567
Fatalities	11,340,000	1,620,000	12,960,000
Injuries	5,369,299	949,953	6,319,252
Totals	**$78,752,736**	**$41,310,083**	**$120,062,819**

Adjusting Incurred Costs beyond 1990

The total annual average costs for vessel casualties, fatalities, and injuries, 1981–1990, were then adjusted for the PRA period, 1996–2025. To find the total annual average costs for tankers for a particular year in 1996–2025, the total annual average costs for tankers 1981–1990 was multiplied by the ratio of total tons of oil transported by tankers in the particular year in 1996–2025 to the average total tons of oil transported by tanker in the years 1981–1990. For example, the total annual average cost for tankers in 1996, assuming a 1-percent growth scenario, would be the cost for tankers, $78,752,736 multiplied by the ratio of total tons of oil transported by tankers in 1996 (624.5 million tons) to average total tons of oil transported by tanker 1981–1990 (555.4 million tons).[49] The 1996 cost for tankers is then $88,550,745. The 1996 cost for barges is analogous: $41,310,083 × (239.5 million tons/216.0 million tons) = $45,804,467.

Estimating Avoided Costs

Once the costs from vessel casualties, fatalities, and injuries, 1996–2025, were calculated, the costs now avoided as a result of OPA 90 were estimated. Avoided costs were estimated in two steps. The first step was to add the three incurred costs for vessel casualties, fatalities, and injuries separately for tankers and barges. The second step was to multiply a rule's first-order effectiveness factor, when considered in isolation, to the sum of the incurred costs.

[49] See Appendix D. The 1996 tonnage for tankers is the average of the tonnage for 1991–1995. Only the sum of the tonnage for tankers and barges increases by the growth rate. Since barge tonnage remains constant, the growth for tankers does not allow a simple growth adjustment.

Rules III (Spill Source Control and Containment), VI (Operational Measures for Single Hull Vessels), VII (Licenses, Certificates, and Mariners' Documents), VIII (Financial Responsibility) have first-order effects for tankers and barges. Table H-3 presents the first-order effectiveness factors for tankers and barges underway for each of the 11 rules in the core group for 1996.

Table H-3
First-Order Effectiveness Factors (Percent) for Core Group Rules for 1996 by Tankers and Barges

PRA Rule	Short Title	Tankers	Barges
I	Double Hulls	0%	0%
II	Deck Spill Control	0	0
III	Spill Source Control and Containment	1	3
IV	Lightering of Single Hull Vessels	0	0
V	Overfill Devices	0	0
VI	Op. Measures of Single Hull Vessels*	12	9
VII	Licenses, Certificates, and Mariners' Documents	1	3
VIII	Financial Responsibility	35	33
IX	Vessel Response Plans	0	0
X	Facility Response Plans	0	0
XI	PWS Equipment & Personnel Requirements	0	0
	Overall Effectiveness	**42.88%**	**42.63%**

* Requires yearly volume adjustment factors; volume factor adjustment for 1996 is 0.861. The adjustment factor accounts for decreasing amounts of oil transported on single hull vessels due to phase out. The rule in the core group that affects only single hull vessels is Rule VII (Licenses, Certificates, and Mariners' Documents).

The avoided costs of all the rules together were estimated by inputting the first-order effectiveness factors through the Procedure (Appendix E) that accounted for double counting. The avoided costs of any subset of rules were estimated by inputting just the applicable first-order effectiveness factors through the Procedure and multiplying by the total cost.

For example, the total cost in 1996 for tankers is \$78,752,736. Assuming 1-percent growth and all rules in the core group considered together, the estimated avoided costs for tankers in 1996 is—

$$0.4288 \times \$78{,}752{,}736 = \$33{,}769{,}173$$

The estimated avoided costs for barges in 1996 is—

$$0.4263 \times \$41{,}310{,}083 = \$17{,}610{,}488$$

Avoided Costs from Lightering Operations and Facilities

Rule VIII is the only core group rule that has first order effects on lightering operations (0.35) and facilities (0.34). However, this PRA estimates that the avoided costs for lightering operations and facilities are zero. The types of accidents that occur during lightering operations or at facilities are usually operational failures of equipment that rarely result in human fatality or injury. While fatalities and injuries have occurred at these spill sources, their expected occurrence is much lower compared with tankers and barges. Because lightering and facility operations take place with tankers and barges not underway, there are no vessel-underway casualties at these spill sources. Avoided costs, therefore, are zero.

Appendix I a Separate Excel Document

J. STUDY PAPER: INCREASED COST OF WATERBORNE TRANSPORTATION OF PETROLEUM IN U.S. WATER DUE TO DOUBLE-HULL REQUIREMENTS (SECTION 4115 OF OPA 90)

David G. St. Amand, Navigistics Consulting

Acronyms Used in this Paper

ACOE	U.S. Army Corps of Engineers
AFRA	Average Freight Rate Assessment
ANS	Alaska North Slope
AR	American Rate
ATRS	American Tanker Rate Schedule
DWT	Deadweight Tonnage
EIA	Energy Information Agency
IRS	Internal Revenue Service
ITB	Integrated Tug-Barge
LMIS	Lloyd's Maritime Information Service
LR-1	Large Range 1 (45,000–79,999 DWT)
LR-2	Large Range 2 (80,000–159,999 DWT)
MARAD	Maritime Administration
MR	Medium Range (25,000–44,999 DWT)
OPA 90	Oil Pollution Act of 1990
OSG	Overseas Shipholding Group
PRA	Programmatic Regulatory Assessment
ULCC	Ultra Large Crude Carrier (320,000–549,999 DWT)
USFRA	U.S. Freight Rate Assessment
VLCC	Very Large Crude Carrier (160,000–319,999 DWT)

Navigistics Consulting, under subcontract to Herbert Engineering, was retained by the U.S. Department of Transportation's Volpe National Transportation Systems Center to assist in the OPA 90 Programmatic Regulatory Assessment by estimating the increased cost of waterborne transportation of petroleum in U.S. waters due to the double-hull requirement in Section 4115 of the Oil Pollution Act of 1990 (OPA 90). This assignment is a follow-on to the work done by Expert Panels A and B in which waterborne oil transportation forecasts were reviewed and the isolated impact of each of the components of OPA 90 were assessed. The expected volumes of waterborne petroleum movements by industry sector were, therefore, used as an input in this analysis. The requested approach to this assignment was to use existing analysis as much as possible to economically develop a reasonable estimate of the increased costs of double-hulls. This assignment draws heavily on the work of the Marine Board's Committee on the Oil Pollution Act of 1990 (Section 4115) Implementation Review. Their report, *Double Hull Tanker Legislation, An Assessment of the Oil Pollution Act of 1990*, was published in 1998. Estimates of potential lost *opportunity* costs due to perceived *early* retirement of tank vessels were beyond the scope of this assignment; however, through the constant supply assumption (i.e., all retired vessels in Jones Act service are replaced with double-hull vessels upon mandatory retirement) these costs are indirectly captured.

Specifically, Navigistics was requested to estimate the following.

- The total industry-wide costs associated with the transport of all waterborne oil (crude and product) subject to the double-hull requirement in U.S. waters in 1996

- The incremental cost of the double-hull requirement for all domestic and foreign flag vessels within U.S. waters for each year between 1990 and 2025 (in constant 1996 dollars)

The calculated cost estimates should include both incremental operating costs and amortized capital costs on an annualized basis.

While a case may be made for attributing the world fleet cost increment to the OPA 90 rules, Navigistics has, as requested, provided results that only include costs attributable to the U.S. trade portion of the total world fleet.

1. Total Industrywide Costs of Waterborne Movements of Petroleum in U.S. Waters

A market-based approach was adopted for estimating the costs of waterborne transportation in U.S. waters of petroleum products and crude oil in 1996. For each market, an estimate of the total amount paid by shippers (or revenue earned by transporters) for the vessel movement was made for 1996. This established the baseline figure for estimating the incremental costs of the double-hull requirement. A cost-based assessment, drawing heavily on the work of the Marine Board Committee, was then made to determine the likely incremental cost of building and operating a double-hull instead of a single-hull tank vessel. This incremental cost, on a percentage basis, was then applied to determine the likely cost of operating an entirely double-hull fleet. This analysis is based on the assumption that demand will be unaffected by the incremental cost of the double hull requirement (i.e., demand is inelastic over the incremental cost range) and that the supply curve will shift upward by the incremental percentage change in cost. Also implied in this analytical approach is that the shape of the supply curve will remain the same with or without the double-hull requirement (other than the constant upward shift). The incremental cost of the double-hull requirement was then made in each year based on the conversion of the fleet from single-hull to double-hull. The conversion schedule was developed based on the age of the individual vessels in each fleet (as of the beginning of 1996) and the retirement schedule in OPA 90 (with an assumption of constant supply in the Jones Act trades).

Because of the constant supply assumption, no costs were assigned to early retirement. Costs were only assigned to increased costs of double-hull over single-hull construction and operation. This overall approach was used in each of the four market segments analyzed. Each market, however, had to be analyzed separately and with different specific calculations performed because of differences in data availability and characteristics in each market. Each of the four market segments analyzed is described below.

- International—movement of crude and petroleum products in foreign flag tankers into (imports) and out of (exports) the U.S.

- Alaskan Crude—Movements of Alaska North Slope (ANS) crude oil from Valdez to its destination market in Jones Act tankers (Virgin Island moves in foreign flag tankers are handled under international)

- U.S. Coastal tanker moves—Movements in Jones Act tankers (as opposed to barges or ITBs) of petroleum products along the coasts of the United States (e.g., U.S. Gulf coast to U.S. Atlantic coast movements)

- U.S. Coastal barge moves—Movements in Jones Act barges or ITBs (subject to OPA 90 double-hull rules) of petroleum products along the coasts of the United States (e.g., U.S. Gulf coast to U.S. Atlantic coast movements)

The purpose of this segmentation was two-fold: first, to provide data in the form needed by the Volpe team for further analysis (i.e., separate tanker and barge data); and second, to properly analyze isolated markets (i.e., international and Jones Act trades).

Inland movements in tank barges are not considered in this analysis primarily because—

- The typical inland tank barge is smaller than 5,000 gross tons, and need not have a double hull as mandated in Section 4115

- However, the inland tank barge industry had largely converted to double-hulls before OPA 90 and is expected to be completely converted well before the 2015 requirement

- Consistent with the above, the Marine Board Committee deemed the inland tank barge industry to be economically beyond the scope of their study

The results of the analysis were tested against publicly available data and interviews with participants in each trade to verify the reasonableness of the results. The analytical approach and estimates of the total cost of waterborne transportation of petroleum in U.S. waters in 1996 are provided for each market segment.

1.A International

The basic approach to estimating the market cost in 1996 of moving imported and exported oil in U.S. waters was to utilize the Worldscale system in conjunction with Average Freight Rate Assessment (AFRA) market data published by the London Tanker Brokers' Panel. AFRA is used to assess the market for tanker transportation services in international trades. It is widely accepted by taxing authorities (including the IRS) for interaffiliate billing purposes (i.e., transfer pricing) for integrated oil companies. This approach requires estimating the volume of petroleum moved in each of the AFRA tanker size categories. The AFRA size categories are listed below.

- Medium range (MR) 25,000–44,999 DWT
- Large Range 1 (LR-1) 45,000–79,999 DWT
- Large Range 2 (LR-2) 80,000–159,999 DWT
- Very Large Crude Carrier (VLCC) 160,000–319,999 DWT
- Ultra Large Crude Carrier (ULCC) 320,000–549,999 DWT

Volumes were estimated using ACOE data on the volume of crude and products moving in and out of the U.S. in international trade. A study for the Marine Board OPA 90 Committee was performed by the Institute of Shipping Analysis (Gothenburg, Sweden) in which the age and size distribution of tankers trading to the U.S. was determined using Lloyd's Maritime Information Service's (LMIS) ship call data for 1994. Energy Information Agency (EIA) data on U.S. imports was also analyzed in conjunction with the knowledge of typical vessel sizes used in the various trades (e.g., VLCCs from the Arabian Gulf, LR-2s from West Africa) to further assess the reasonableness of the results.

Exhibit 1
International Waterborne Petroleum Trade by AFRA

International AFRA Size Class, kDWT	Percentage of Total Carried
MR 25–45	10%
LR-1 45–80	20
LR-2 80–160	40
VLCC 160–320	25
ULCC 320–550	5

Source: Navigistics analysis

No fixed differentials for Oil Pollution Liability Insurance were included.[a] The AFRA rates used in the analysis are the average for all of 1996 as provided by the London Tanker Brokers Panel for this study.

Exhibit 2
Cost of Waterborne Petroleum Trade with U.S. Internationally Trading Tankers

AFRA Class	AFRA, Percent of Worldscale	Worldscale, $/Ton	Percentage of Total	Est. Million Tons Transported	Total 1996 Cost, $Millions
MR 25–45	180.8	$4.08	10%	52.1	$378
LR-1 45–80	127.1	4.08	20	102.4	531
LR-2 80–160	94.1	8.97	40	204.8	1,729
VLCC 160–320	60.3	17.60	25	128.0	1,358
ULCC 320–550	48.9	17.60	5	25.6	220
Totals			**100%**	**512.0**	**$4,216**

Source: AFRA—London Tanker Brokers Panel 1996 average
Worldscale $/Ton—Worldscale Association (NYC), Inc.
Percentage of Total—Navigistics analysis
Estimated Tons Transported—percentage and ACOE data provided by the Volpe Center

The analysis indicates that the market-based cost of waterborne transportation of petroleum movements in U.S. waters in international commerce in 1996 was approximately $4.2 billion.

1.B Alaskan Crude Trade (Jones Act)

Estimating the market cost of Alaskan crude transportation presented a unique challenge, given the large portion of the trade handled in proprietary vessels by the major producers. The following publicly available information does provide some insight into the size and cost of the trade.

- Alaska's Department of Revenue estimates the actual cost of marine transportation was $1.63 per barrel in 1996 (page 20 Spring 1997 Revenue Sources Book by the Alaska Department of Revenue). Actual Alaskan crude production was 1.516 million barrels per day. These data would indicate a total waterborne transportation cost of approximately $900 million.

- Overseas Shipholding Group (OSG) annual report for 1996 states that it received revenue of $98.3/49.5/63.7 million from BP (USA) in 1996/1995/1994 respectively. Virtually all of this revenue was from the Alaskan crude trade.

OSG's reported 1996 revenue from the Alaskan trade of $98.3 million represents a market share of approximately 11 percent. This also approximates OSG's share of the vessel capacity

[a] The increased cost of waterborne transportation related to potential increased liability costs were assessed by the Volpe team separately.

employed in the Alaskan crude trade on a DWT basis. Therefore, it was concluded that the cost of waterborne transportation of Alaskan crude was approximately $900 million in 1996. Of this amount approximately 16 percent is estimated (based on data from the Association of Shipbrokers and Agents and interviews with two of the major producers) to cover port and environmental costs (i.e., non-ship direct costs).[b] The Alaskan crude trade, therefore, is estimated to cost approximately $750 million for the Jones Act tankers involved.

1.C Coastal Tanker Trade (Jones Act)

The basic approach to estimating the market cost in 1996 of moving petroleum products along and between the U.S. coasts in the Jones Act trades was similar to the approach utilized in the international trades. The American Tanker Rate Schedule, also called ATRS or the AR system, as administered by the Association of Ship Brokers and Agents (USA) Inc., was used in conjunction with the U.S. Freight Rate Assessment (USFRA) system, administered by the Shipping Cost Analysis Corporation. The ATRS/USFRA system is similar to the Worldscale/AFRA system. The ATRS/USFRA system, however, is applicable only to Jones Act voyages. The USFRA size categories applicable to this analysis are—

- 30,000–39,999 DWT
- 40,000–89,999 DWT

Based on the capacity of the tankers available for use in the coastal trades in 1996, it was estimated that 56 percent of the petroleum carried was by 30 to 40 kDWT tankers and 44 percent in product tankers over 40 kDWT (only tankers over 40 kDWT identified by MARAD as participating in the coastal petroleum products trade were included in this analysis).

[b] The increased cost of waterborne transportation related to potential increased liability and other environmental costs are being assessed by Volpe separately.

Exhibit 3
Cost of Waterborne Petroleum Trade in U.S. Waters, Jones Act Coastal Tankers

Tankers, kDWT	USFRA, Percent of ATRS	Average ATRS, $/Ton	Percentage of Total	Million Tons Transported	Total 1996 Cost, $Millions
30–40	187.0	$4.75	56%	32	$284
40–90	167.3	4.75	44	25	199
Totals			**100%**	**57**	**$483**

Source: USFRA—Shipping Cost Analysis Corporation average for 1996
Average ATRS—Navigistics analysis of coastal tanker trade volumes and ATRS data
Percentage of Total—Navigistics analysis of tanker capacity in the coastal products trade
Million Tons Transported—ACOE data for 1996

Based on the above analysis, the cost of moving petroleum products in the U.S. Jones Act coastal tanker trade was estimated to be approximately $480 million in 1996.

1.D Coastal Barge Trade (Jones Act)

The cost of the U.S. coastal barge trade was estimated using the AR system and estimated freight rates. The estimated freight rates were developed based on interviews with four of the primary barge operators active in the trade. Most coastal barge rates, however, are negotiated on a route-specific dollar-per-barrel basis. Freight rates provided in that form were converted to the AR system for use in this analysis.

Exhibit 4
Cost of Waterborne Petroleum Trade in U.S. Waters, Jones Act Coastal Barges

Coastal Product	Avg. Rate, Percent of ATRS	Average ATRS, $/Ton	Million Tons Transported	Total 1996 Cost, $Millions
Barge	**192**	**$3.50**	**55**	**$370**

Source: Avg. Rate—Based on interviews with four barge operators, average for 1996
Average ATRS—Navigistics analysis of coastal barge trade volumes and ATRS data
Million Tons Transported—ACOE data for 1996

Based on the above analysis, the cost of moving petroleum products in the U.S. Jones Act coastal barge trade was approximately $370 million in 1996. This amount is consistent with the revenue reported by the largest barge operator, Maritrans, in its 1996 Annual Report. Maritrans reported total revenue of $127 million, of which approximately $98 million is estimated (by Navigistics) to have been derived in the coastal transportation of petroleum products. Maritrans also reported carrying 218 million barrels of petroleum, of which approximately 16 million tons was estimated (by Navigistics) to have been carried in the coastal petroleum products trade. Both the tonnage and revenue amounts represent consistent market shares of approximately 26 to 29 percent. This indicates that the total market estimate of $370 million is reasonable.

2. Incremental Costs of Waterborne Movement of Petroleum in U.S. Waters Due to the Double-Hull Requirements in OPA 90

The next step in the analysis was to estimate the increased cost of transporting petroleum in U.S. waters due to the double-hull requirement. This analysis required the following.

- Estimating the increased construction cost of a double-hull over a single-hull tank vessel
- Estimating the increased operating cost of a double-hull over a single-hull tank vessel
- Combining the increased operating and capital costs on an annual percentage basis for use with the total estimated cost
- Verifying that the results are reasonable

2.A Increased Cost of Double Hulls—International Tanker Trade

The Marine Board's Committee on the Oil Pollution Act of 1990 (Section 4115) Implementation Review estimated the incremental costs of double-hulls for tankers, as shown in Exhibit 5.

Exhibit 5
Increased Capital and Operating Costs of Double-Hull Tankers, International Tanker Fleet, Percentage Increase over Single-Hull Tankers

Tanker Size	Capital Cost Increase	Operating Cost Increase
Product Tanker	10%	13%
AFRAmax	17	13
Suezmax	17	11
VLCC	15	5

Source: *Double Hull Tanker Legislation: An Assessment of the Oil Pollution Act of 1990*, report of the Marine Board's Committee on the Oil Pollution Act of 1990 (Section 4115) Implementation Review

Navigistics then estimated the overall cost increase on each tanker size by combining the operating and capital costs for each vessel size. Capital costs were assessed on a levelized basis using a 15 percent risk adjusted discount rate (12 percent real rate to maintain constant 1996 dollars) over a 25-year life. Estimates were made on the basis of a full U.S. tax rate and a zero tax rate. In each case advance payments of 40 percent of total cost were assumed to be made two years prior to delivery, 35 percent 1 year prior to delivery, and the balance of 25 percent was assumed to be paid at delivery. For the U.S. tax rate case, a 35 percent tax rate was used with 10-year Macrs depreciation and a gross-up to cover taxes owed was included. Operating costs from the Drewry's Report "Ship Costs—The Economics of Ship Acquisition and Operation" (February 1997) were used. The expected overall cost increase on each tanker size is shown in Exhibit 6.

Exhibit 6
Overall Expected Cost Increase of Double-Hull Tankers, International Tanker Fleet, Percentage Increase over Single-Hull Tankers

Tanker Size	Capital Cost, $Millions	Annualized Capital Cost, $Millions	Annual Non-Fuel Operating Cost, $Millions	Overall Percent Increase Due to Double Hulls
Product Tanker	$32	$5.3	$2.0	10.6%
AFRAmax	44	7.0	2.3	15.7
Suezmax	54	8.6	2.5	15.2
VLCC	85	13.7	3.5	12.7

Source: Capital Costs—Navigistics analysis of Drewry's, Clarkson's, and Lloyd's data
Annualized Capital Costs—Navigistics analysis
Annual Non-Fuel Operating Costs—Navigistics analysis of Drewry's data
Overall Percent Increase Due to Double Hulls—Navigistics analysis

The increased cost of double hulls, in 1996 dollars, if all petroleum moving in international trade to the U.S. in 1996 had moved in double-hull tankers is shown Exhibit 7.

Exhibit 7
Overall Annual Expected Cost Increase of Double-Hull Tankers in U.S. Waters if all 1996 Cargoes Were Carried in Double Hulls, International Tanker Fleet, $Millions

AFRA Class	Market-Based Cost, 1996 $Millions	Overall Percent Increase Due to Double Hulls	Increased Cost Due to Double Hulls, $Millions
MR 25–45	$378	10.6%	$40
LR-1 45–80	531	13.2	70
LR-2 80–160	1,729	15.5	267
VLCC 160–320	1,358	12.7	173
ULCC 320–550	220	12.7	28
Totals	**$4,216**		**$577**

Source: Market-Based Cost—Exhibit 2
Overall Percent Increase Due to Double Hulls—Navigistics analysis using Exhibit 6

The estimated increased annual cost, in 1996 dollars, of transporting oil to the U.S. in a fully converted (to double hulls) international tanker fleet is $577 million.

2.B Increased Cost of Double Hulls—U.S. (Jones Act) Construction Costs

Because of the lack of a large and diverse construction program for double-hull tankers in U.S. shipyards, it was necessary to estimate the construction costs in U.S. shipyards using a multiplier on foreign costs. Herbert Engineering provided estimates of the U.S. shipyard cost multiplier for tanker construction, which are shown in Exhibit 8.

Exhibit 8
Estimated Jones Act Tanker Construction Costs, $Millions

Tanker Size, kDWT	Foreign Costs, $Millions	Estimated U.S. Multiplier	Estimated U.S. Cost, $Millions
40	$33.0	1.50–2.00	$58
95	42.0	1.75–2.25	84
140	52.5	2.00–2.50	118
280	83.0	2.00–2.50	187

Source: Foreign Costs—Drewry's
Estimated U.S. Multiplier—Herbert Engineering analysis
Estimated U.S. Cost—based on midrange of multiplier

A relationship between deadweight and capital cost was developed using linear regression for estimating replacement costs for each existing single-hull vessel. Incremental double-hull costs (over single-hull) were estimated using the international relationships identified earlier.

U.S. barge costs were estimated based on interviews with barge owners and shipyards. A 25 percent incremental capital cost of a double hull was used for barges.

2.C Increased Cost of Double Hulls—Alaskan (Jones Act) Tanker Trade

Based on discussions with naval architects and operators in the Alaskan tanker trade it was concluded that the percentage cost increases used in the International tanker trade would be applicable (on a percentage but not absolute basis) to the Jones Act trades. This assumption was tested against estimated capital and operating costs for Alaskan Jones Act tankers and determined to be reasonable. The share of Alaskan crude carried in the various size vessels was determined based on MARAD data on the Alaskan trade (these data are available for liftings by each vessel voyage and destination—percentage of tons carried was used as a proxy for percentage of costs/revenue). These percentages and the total cost of conversion are shown in Exhibit 9.

Exhibit 9
Overall Annual Expected Cost Increase of Double-Hull Tankers in U.S. Waters if all 1996 Cargoes Were Carried in Double Hulls, Alaskan Tanker Trade, $Millions

Tanker Size, kDWT	Percent of Tons Carried	Overall Percent Increase Due to Double Hulls	Increased Cost Due to Double Hulls, $Millions
60–90	16%	13.3%	$15.8
90–130	41	15.5	47.8
130–200	29	14.1	31.2
> 200	13	12.7	12.9
Totals	**100%**		**$107.6**

Source: Percent of Tons Carried—Navigistics analysis of MARAD data
Overall Percent Increase Due to Double Hulls—Navigistics analysis from Exhibit 6
Increased Cost of Double Hulls—Navigistics analysis

The estimated annual cost, in 1996 dollars, of fully converting the Alaskan tanker fleet to double-hulls is $108 million.

This estimate was verified by annualizing the estimated capital cost (using the previously described U.S. tax case capital model) of building new double-hull Jones Act tankers to replace every current Alaskan single-hull tanker in its OPA 90 retirement year and summing the incremental (double over single-hull) capital costs (i.e., for a vessel retired in 2008, its incremental replacement cost was calculated and converted into a levelized annual after-tax cost for the next 25 years—the same was done for all other tankers and the levelized annual costs summed for each year for all replaced vessels). The increased capital cost in 2015, when all Alaskan trade tankers must have double hulls, was estimated to be $90 million. The total annual incremental cost of building and operating the Alaskan (Jones Act) tanker fleet as double hulls of $110 million, therefore, was considered to be reasonable.

2.D Increased Cost of Double Hulls—Coastal (Jones Act) Tanker Trade

As with the Alaskan (Jones Act) tanker trade, the international tanker trade's incremental costs due to the double-hull requirement was considered to be reasonable for estimating the impact on the coastal trade. The results are shown in Exhibit 10.

Exhibit 10
Overall Annual Expected Cost Increase of Double-Hull Tankers in U.S. Waters if all 1996 Cargoes Were Carried in Double Hulls, Coastal Tanker Trade, $Millions

Tanker Size, kDWT	Million Tons Transported	Cost, 1996 $Millions	Overall Percent Increase Due to Double Hulls	Increased Cost Due to Double Hulls, $Millions
30–40	32	$283.53	10.6%	$30.1
40–90	25	199.30	13.2	26.2
Totals	**57**	**$482.83**		**$56.3**

Source: Million Tons Transported—ACOE data for 1996
Cost, 1996—Exhibit 3
Overall Percent Increase Due to Double Hulls—Navigistics analysis

The above analysis indicates that the incremental cost of the double-hull mandate for the coastal product fleet is approximately $60 million per year. However, estimating the incremental annualized capital cost (using the previously described U.S. tax case capital model) of building new double-hull Jones Act tankers to replace every current single-hull tanker operating in the coastal fleet in its OPA 90 retirement year and summing the incremental (double over single-hull) capital costs indicates that the cost is more on the order of $94 million per year. This raises several possibilities regarding the validity of the original assumptions. The most likely flaw in the original assumptions (as they apply to this portion of the U.S. trading fleet only) is that current market rates are not compensatory for new construction. This problem would cause the application of the incremental percentage increase due to double-hulls to significantly understate the cost (the incremental cost is the difference with a new single-hull tanker).

A MARAD study, "Domestic Product Tanker Markets" (January 1996) stated that break-even rates for a new 45,000 DWT double-hull products tanker is approximately $30,000 per day.

Freight rates in 1996 were more on the level of $17,000 to $22,000 per day. This freight rate/new building requirement ratio is indicative of a declining market with excess tonnage. A more balanced market would likely produce freight rates closer to $30,000 per day. This analysis raises the quandary of how to apply the increased cost to convert the "old" coastal tanker fleet into a "new" single-hull fleet. Is this a cost of the retirement provision of OPA 90? Or is this a cost of the excess supply or a declining market situation? Without specific knowledge of the material condition of the Coastal Jones Act product tanker fleet, it is not possible to say if it could trade forever with minimal costs (which is what would be implied by adding the cost to build 'new' single-hull tankers to the double-hull cost). The current Jones Act coastal product tanker fleet has an average age of over 27 years. Costs attributed to early retirement are beyond the scope of this study. It should also be noted that "new" single-hull tankers would have significantly lower operating costs than most of the "old" tankers that they would replace. The fuel consumption of a new diesel power plant is significantly lower than the steam power plants being replaced. In addition, manning requirements have decreased, thereby reducing crew costs on newer vessels. In any event, the incremental cost of a double-hull over single-hull fleet should be increased to at least $95 million.

2.E Increased Cost of Double Hulls—Coastal (Jones Act) Barge Trade

The increased cost of building and operating a Coastal (Jones Act) barge is estimated to be approximately 25 percent. This amount is valid for both the capital and operating costs. The 25 percent incremental cost estimate is based on interviews with barge builders and operators. It is also reasonable in relation to the incremental tanker cost estimates. Barges will have a higher incremental percentage capital cost because the costs of building the power plant and full crew quarters are attributable to the tug and are, therefore, not included in the denominator of the percentage cost increase calculation (as they are with a tanker). Similarly, crew and power plant operating costs are excluded from the denominator with a barge. However, the market-based estimate of the cost of the Coastal Jones Act barge trade includes the costs of the tug. The overall incremental annual cost of building and operating a double-hull over a single-hull tank barge is estimated to be 25 percent (excluding the tug). This roughly equates to an overall fleet cost increase of approximately 17 percent (two-thirds of the total) when the tug is included. This indicates that the total incremental cost of a double-hull fleet would be $60 million (17 percent of $370 million).

This estimate was verified by annualizing the estimated capital cost (using the previously described U.S. tax case capital model) of building new double-hull Jones Act barges to replace every current single-hull barge in its OPA 90 retirement year and summing the incremental (double over single-hull) capital costs. The sum of the annualized incremental increase (due to double-hulls) in capital cost for replacing all existing barges in 2015, when all tank barges must have double-hulls, was estimated to be $50 million. The total annual incremental cost of building and operating the Coastal (Jones Act) tank barge fleet as double-hulls of $60 million, therefore, was considered to be reasonable.

3. Recommended Costs for the Volpe Center to Use in Double Hull PRA by Year and Trade

The incremental costs to use in the double-hull Programmatic Regulatory Assessment will vary by segment. In the international trade the incremental cost of $1.128 per ton (based on the increased costs of double hulls of $577 million shown in Exhibit 7 and 512 million tons transported per Exhibit 2) should be used (tons times percent double-hull times $1.128 for each year from 1990 through 2025). In the Jones Act trades the volume assessments reviewed by Expert Panel A reflect expected constant volumes in the coastal tanker and barge markets. With an assumption of constant supply (i.e., all existing single-hull Jones Act tankers and barges are replaced), the costs should correspond with the OPA 90 retirement schedules. These costs are shown by year in Attachment A. The Alaskan trade is more difficult to assess given the expected decrease in volume. The Alaskan tanker incremental costs were reduced by the ratio of future years production to 1996 production. These costs for 1996 are summarized in Exhibit 11.

Exhibit 11
Summary of Overall Annual Expected Cost Increase of Double-Hull Tankers in U.S. Waters if all 1996 Cargoes Were Carried in Double Hulls, All Trades, 1996 $Millions

Trade	Total Estimated Cost	Incremental Cost	Capital Cost	Operating Cost
International	**$4,216**	$577	$432	$145
Alaskan Tanker	**750**	110	90	20
Coastal Tanker	**480**	95	75	20
Coastal Barge	**370**	60	50	10
Totals	**$5,816**	**$842**	**$647**	**$195**

Source: Million Tons Transported—ACOE data for 1996
Cost, 1996—Exhibit 3
Overall Percent Increase Due to Double Hulls—Navigistics analysis

Using the figures in the above table with the scheduled phase-out of single-hull tankers, the estimated cost of the double-hull provision of OPA 90 was estimated for each year from 1990 through 2025 using the 1-percent growth scenario provided by the Volpe team (and reviewed by Expert Panel A). The results of that analysis are provided as Attachments A and B to this report.

Attachment A
1-Percent Growth Scenario OPA 90 Double Hull Incremental Cost Analysis

Year	Single Hull (%)	Total Million Tons	Tanker Million Tons	Coastal Barges Million Tons	Coastal Tankers Million Tons	Alaska Tankers Million Tons	Intl. Tankers Million Tons	Alaska Tankers before Decline ($M)	Alaska Decline Factor (%)	Alaska Tankers after Decline ($M)	Coastal Tankers ($M)	Intl. Tankers ($M)	Total All Tankers ($M)	Coastal Barges ($M)	Total Tankers & Barges ($M)
1990	92.0%	861.6	620.4	241.3		93.9									
1991	90.9	826.6	595.2	231.5		91.2									
1992	89.8	839.3	604.3	235.0		90.7									
1993	88.7	868.2	625.1	243.1		85.6									
1994	87.6	896.9	645.8	251.1		83.1									
1995	86.5	846.3	609.4	237.0	57.0	79.8	472.6								
1996	86.1	864.0	624.5	239.5	57.0	74.7	492.8	$0.0	100.0%	$0.0	$0.0	$77.1	$77.1	$0.0	$77.1
1997	85.8	872.7	645.8	239.5	57.0	72.4	503.8	0.0	96.9	0.0	2.5	81.0	83.4	0.0	83.4
1998	84.7	881.4	609.4	239.5	57.0	69.6	515.3	7.0	93.1	6.5	7.4	88.8	102.8	0.0	102.8
1999	78.5	890.2	624.5	239.5	57.0	65.5	528.2	14.1	87.7	12.3	9.2	128.1	149.7	0.0	149.7
2000	73.1	899.1	633.2	239.5	57.0	65.3	537.4	41.0	87.3	35.8	20.9	163.1	219.7	0.0	219.7
2001	71.0	908.1	641.9	239.5	57.0	66.3	545.3	58.7	88.7	52.0	33.5	178.4	264.0	1.2	265.2
2002	68.4	917.2	650.7	239.5	57.0	62.8	557.9	67.7	84.1	56.9	37.2	198.8	292.8	2.5	295.3
2003	63.5	926.4	659.6	239.5	57.0	59.0	570.9	67.7	78.9	53.4	40.8	235.0	329.2	4.3	333.5
2004	56.0	935.6	668.6	239.5	57.0	54.7	584.4	71.2	73.2	52.2	47.8	290.0	389.9	7.7	397.7
2005	47.2	945.0	677.7	239.5	57.0	51.0	597.5	80.1	68.3	54.7	55.5	355.6	465.8	33.2	499.0
2006	38.6	954.4	686.9	239.5	57.0	47.5	610.4	93.4	63.6	59.4	64.9	422.5	546.7	39.1	585.8
2007	33.5	964.0	696.1	239.5	57.0	44.5	623.0	98.2	59.5	58.5	64.9	467.5	590.8	46.1	636.9
2008	30.8	973.6	705.5	239.5	57.0	41.7	635.4	101.8	55.8	56.8	64.9	495.8	617.4	52.2	669.6
2009	28.6	983.4	714.9	239.5	57.0	39.1	647.7	104.8	52.3	54.8	69.6	521.4	645.8	53.7	699.5
2010	21.8	993.2	724.5	239.5	57.0	37.2	659.5	110.0	49.8	54.7	69.6	581.9	706.2	55.9	762.1
2011	21.0	1,002.1	734.1	239.5	57.0	35.2	671.5	110.0	47.0	51.8	78.9	598.5	729.1	55.9	785.0
2012	20.5	1,013.2	743.9	239.5	57.0	33.3	683.3	110.0	44.6	49.1	91.2	612.6	752.9	55.9	808.7
2013	20.0	1,023.3	753.7	239.5	57.0	31.6	695.2	110.0	42.2	46.5	95.0	627.7	769.1	55.9	852.0
2014	19.3	1,033.5	763.6	239.5	57.0	29.9	707.1	110.0	40.0	44.0	95.0	643.9	782.9	55.9	838.7
2015	0.0	1,043.9	773.7	239.5	57.0	28.5	718.8	110.0	38.2	42.0	95.0	810.8	947.8	60.0	1,007.8
2016	0.0	1,043.9	783.8	239.5	57.0	27.3	720.1	110.0	36.5	40.1	95.0	812.3	947.4	60.0	1,007.4
2017	0.0	1,043.9	794.0	239.5	57.0	25.6	721.8	110.0	34.2	37.7	95.0	814.2	946.8	60.0	1,006.8
2018	0.0	1,043.9	804.4	239.5	57.0	23.4	723.9	110.0	31.3	34.5	95.0	816.6	946.1	60.0	1,006.1
2019	0.0	1,043.9	804.4	239.5	57.0	21.7	725.7	110.0	29.0	31.9	95.0	818.6	945.5	60.0	1,005.5
2020	0.0	1,043.9	804.4	239.5	57.0	20.1	727.3	110.0	26.8	29.5	95.0	820.4	944.9	60.0	1,004.9
2021	0.0	1,043.9	804.4	239.5	57.0	18.6	728.8	110.0	24.8	27.3	95.0	822.1	944.4	60.0	1,004.4
2022	0.0	1,043.9	804.4	239.5	57.0	17.2	730.2	110.0	23.0	25.3	95.0	823.6	943.9	60.0	1,003.9
2023	0.0	1,043.9	804.4	239.5	57.0	15.9	731.5	110.0	21.3	23.4	95.0	825.1	943.5	60.0	1,003.5
2024	0.0	1,043.9	804.4	239.5	57.0	14.7	732.7	110.0	19.7	21.6	95.0	826.4	943.1	60.0	1,003.1
2025	0.0	1,043.9	804.4	239.5	57.0	13.6	733.8	110.0	18.2	20.0	95.0	827.7	942.7	60.0	1,002.7

Attachment B
Sources of Information Used in the Analysis
(Interviews, Purchase, Review of Publicly Available Purchased Material)

Overseas Shipholding Group/Maritime Overseas Corporation (tanker owner/operator in the International, Alaskan, and coastal Jones Act trade)

Kirby Corporation (tanker and barge owner/operator in the Jones Act coastal trade)

Maritrans (barge owner/operator in the Jones Act coastal trade)

Morania (barge owner/operator in the Jones Act coastal trade)

Reinauer Transportation Company (barge owner/operator in the Jones Act coastal trade)

Allied Towing Corporation (barge owner/operator in the Jones Act coastal trade)

Herbert Engineering

Clarkson Research

Drewry

Marine Board OPA 90 Committee

MARAD

State of Alaska Department of Revenue

EXXON Company, USA

BP Oil (USA)

Halter Marine (U.S. barge builder)

Army Corps of Engineers *Waterborne Commerce Statistics*

U.S. Department of Energy—EIA Statistics

Worldscale Association (NYC), Inc.

Shipping Cost Analysis Corporation

Association of Ship Brokers and Agents (USA), Inc.

London Tanker Brokers' Panel, Ltd.

U.S. Coast Guard

Institute of Shipping Analysis (Gothenburg, Sweden)

K. EXECUTIVE ORDER NO. 12866: REGULATORY PLANNING AND REVIEW, SEPTEMBER 30, 1993

The American people deserve a regulatory system that works for them, not against them: a regulatory system that protects and improves their health, safety, environment, and well-being and improves the performance of the economy without imposing unacceptable or unreasonable costs on society; regulatory policies that recognize that the private sector and private markets are the best engine for economic growth; regulatory approaches that respect the role of State, local, and tribal governments; and regulations that are effective, consistent, sensible, and understandable. There is no such regulatory system today.

With this Executive order, the federal government begins a program to reform and make more efficient the regulatory process. The objectives of this Executive order are to enhance planning and coordination with respect to both new and existing regulations; to reaffirm the primacy of Federal agencies in the regulatory decision-making process; to restore the integrity and legitimacy of regulatory review and oversight; and to make the process more accessible and open to the public. In pursuing these objectives, the regulatory process shall be conducted so as to meet applicable statutory requirements and with due regard to the discretion that has been entrusted to the Federal agencies.

Accordingly, by the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered as follows:

Section 1. Statement of Regulatory Philosophy and Principles.

(a) The Regulatory Philosophy. Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. In deciding whether and how to regulate, agencies should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Costs and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider. Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach.

(b) The Principles of Regulation. To ensure that the agencies' regulatory programs are consistent with the philosophy set forth above, agencies should adhere to the following principles, to the extent permitted by law and where applicable:

(1) Each agency shall identify the problem that it intends to address (including, where applicable, the failures of private markets or public institutions that warrant new agency action) as well as assess the significance of that problem.

(2) Each agency shall examine whether existing regulations (or other law) have created, or contributed to, the problem that a new regulation is intended to correct and whether those regulations (or other law) should be modified to achieve the intended goal of regulation more effectively.

(3) Each agency shall identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

(4) In setting regulatory priorities, each agency shall consider, to the extent reasonable, the degree and nature of the risks posed by various substances or activities within its jurisdiction.

(5) When an agency determines that a regulation is the best available method of achieving the regulatory objective, it shall design its regulations in the most cost effective manner to achieve the regulatory objective. In doing so, each agency shall consider incentives for innovation, consistency, predictability, the costs of enforcement and compliance (to the government, regulated entities, and the public), flexibility, distributive impacts, and equity.

(6) Each agency shall assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.

(7) Each agency shall base its decisions on the best reasonably obtainable scientific, technical, economic, and other information concerning the need for, and consequences of, the intended regulation.

(8) Each agency shall identify and assess alternative forms of regulation and shall, to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt.

(9) Wherever feasible, agencies shall seek views of appropriate State, local, and tribal officials before imposing regulatory requirements that might significantly or uniquely affect those governmental entities. Each agency shall assess the effects of Federal regulations on State, local, and tribal governments, including specifically the availability of resources to carry out those mandates, and seek to minimize those burdens that

uniquely or significantly affect such governmental entities, consistent with achieving regulatory objectives. In addition, as appropriate, agencies shall seek to harmonize Federal regulatory actions with related State, local, and tribal regulatory and other governmental functions.

(10) Each agency shall avoid regulations that are inconsistent, incompatible, or duplicative with its other regulations or those of other Federal agencies.

(11) Each agency shall tailor its regulations to impose the least burden on society, including individuals, businesses of differing sizes, and other entities (including small communities and governmental entities), consistent with obtaining the regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations.

(12) Each agency shall draft its regulations to be simple and easy to understand, with the goal of minimizing the potential for uncertainty and litigation arising from such uncertainty.

Section 2. Organization.

An efficient regulatory planning and review process is vital to ensure that the federal government's regulatory system best serves the American people.

(a) The Agencies. Because Federal agencies are the repositories of significant substantive expertise and experience, they are responsible for developing regulations and assuring that the regulations are consistent with applicable law, the President's priorities, and the principles set forth in this Executive order.

(b) The Office of Management and Budget. Coordinated review of agency rulemaking is necessary to ensure that regulations are consistent with applicable law, the President's priorities, and the principles set forth in this Executive order, and that decisions made by one agency do not conflict with the policies or actions taken or planned by another agency. The Office of Management and Budget (OMB) shall carry out that review function. Within OMB, the Office of Information and Regulatory Affairs (OIRA) is the repository of expertise concerning regulatory issues, including methodologies and procedures that affect more than one agency, this Executive order, and the President's regulatory policies. To the extent permitted by law, OMB shall provide guidance to agencies and assist the President, the Vice President, and other regulatory policy advisors to the President in regulatory planning and shall be the entity that reviews individual regulations, as provided by this Executive order.

(c) The Vice President. The Vice President is the principal advisor to the President on, and shall coordinate the development and presentation of recommendations concerning, regulatory policy, planning, and review, as set forth in this Executive order. In fulfilling their responsibilities under this Executive order, the President and the Vice President shall be assisted by the regulatory policy advisors within the Executive Office of the President and by such agency officials and personnel as the President and the Vice President may, from time to time, consult.

Section 3. Definitions.

For purposes of this Executive order:

(a) '**Advisors**' refers to such regulatory policy advisors to the President as the President and Vice President may from time to time consult, including, among others:

(1) the Director of OMB;

(2) the Chair (or another member) of the Council of Economic Advisers;

(3) the Assistant to the President for Economic Policy;

(4) the Assistant to the President for Domestic Policy;

(5) the Assistant to the President for National Security Affairs;

(6) the Assistant to the President for Science and Technology;

(7) the Assistant to the President for Intergovernmental Affairs;

(8) the Assistant to the President and Staff Secretary;

(9) the Assistant to the President and Chief of Staff to the Vice President;

(10) the Assistant to the President and Counsel to the President;

(11) the Deputy Assistant to the President and Director of the White House Office on Environmental Policy; and

(12) the Administrator of OIRA, who also shall coordinate communications relating to this Executive order among the agencies, OMB, the other Advisors, and the Office of the Vice President.

(b) '**Agency**', unless otherwise indicated, means any authority of the United States that is an 'agency' under 44 U.S.C. 3502(1), other than those considered to be independent regulatory agencies, as defined in 44 U.S.C. 3502(10).

(c) **'Director'** means the Director of OMB.

(d) **'Regulation** or **'rule'** means an agency statement of general applicability and future effect, which the agency intends to have the force and effect of law, that is designed to implement, interpret, or prescribe law or policy or to describe the procedure or practice requirements of an agency. It does not, however, include:

(1) Regulations or rules issued in accordance with the formal rulemaking provisions of 5 U.S.C. 556, 557;

(2) Regulations or rules that pertain to a military or foreign affairs function of the United States, other than procurement regulations and regulations involving the import or export of non-defense articles and services;

(3) Regulations or rules that are limited to agency organization, management, or personnel matters; or

(4) Any other category of regulations exempted by the Administrator of OIRA.

(e) **'Regulatory action'** means any substantive action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking.

(f) **'Significant regulatory action'** means any regulatory action that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive order.

Section 4. Planning Mechanism.

In order to have an effective regulatory program, to provide for coordination of regulations, to maximize consultation and the resolution of potential conflicts at an early stage, to involve the public and its State, local, and tribal officials in regulatory planning, and to ensure that new or revised regulations promote the President's priorities and the principles set forth in this Executive order, these procedures shall be followed, to the extent permitted by law:

(a) Agencies' Policy Meeting. Early in each year's planning cycle, the Vice President shall convene a meeting of the Advisors and the heads of agencies to seek a common understanding of priorities and to coordinate regulatory efforts to be accomplished in the upcoming year.

(b) Unified Regulatory Agenda. For purposes of this subsection, the term 'agency' or 'agencies' shall also include those considered to be independent regulatory agencies, as defined in 44 U.S.C. 3502(10). Each agency shall prepare an agenda of all regulations under development or review, at a time and in a manner specified by the Administrator of OIRA. The description of each regulatory action shall contain, at a minimum, a regulation identifier number, a brief summary of the action, the legal authority for the action, any legal deadline for the action, and the name and telephone number of a knowledgeable agency official. Agencies may incorporate the information required under 5 U.S.C. 602 and 41 U.S.C. 402 into these agendas.

(c) The Regulatory Plan. For purposes of this subsection, the term 'agency' or 'agencies' shall also include those considered to be independent regulatory agencies, as defined in 44 U.S.C. 3502(10).

> (1) As part of the Unified Regulatory Agenda, beginning in 1994, each agency shall prepare a Regulatory Plan (Plan) of the most important significant regulatory actions that the agency reasonably expects to issue in proposed or final form in that fiscal year or thereafter. The Plan shall be approved personally by the agency head and shall contain at a minimum:
>
> > (A) A statement of the agency's regulatory objectives and priorities and how they relate to the President's priorities;
> >
> > (B) A summary of each planned significant regulatory action including, to the extent possible, alternatives to be considered and preliminary estimates of the anticipated costs and benefits;
> >
> > (C) A summary of the legal basis for each such action, including whether any aspect of the action is required by statute or court order;
> >
> > (D) A statement of the need for each such action and, if applicable, how the action will reduce risks to public health, safety, or the environment, as well as how the magnitude of the risk addressed by the action relates to other risks within the jurisdiction of the agency;

(E) The agency's schedule for action, including a statement of any applicable statutory or judicial deadlines; and

(F) The name, address, and telephone number of a person the public may contact for additional information about the planned regulatory action.

(2) Each agency shall forward its Plan to OIRA by June 1st of each year.

(3) Within 10 calendar days after OIRA has received an agency's Plan, OIRA shall circulate it to other affected agencies, the Advisors, and the Vice President.

(4) An agency head who believes that a planned regulatory action of another agency may conflict with its own policy or action taken or planned shall promptly notify, in writing, the Administrator of OIRA, who shall forward that communication to the issuing agency, the Advisors, and the Vice President.

(5) If the Administrator of OIRA believes that a planned regulatory action of an agency may be inconsistent with the President's priorities or the principles set forth in this Executive order or may be in conflict with any policy or action taken or planned by another agency, the Administrator of OIRA shall promptly notify, in writing, the affected agencies, the Advisors, and the Vice President.

(6) The Vice President, with the Advisors' assistance, may consult with the heads of agencies with respect to their Plans and, in appropriate instances, request further consideration or inter-agency coordination.

7) The Plans developed by the issuing agency shall be published annually in the October publication of the Unified Regulatory Agenda. This publication shall be made available to the Congress; State, local, and tribal governments; and the public. Any views on any aspect of any agency Plan, including whether any planned regulatory action might conflict with any other planned or existing regulation, impose any unintended consequences on the public, or confer any unclaimed benefits on the public, should be directed to the issuing agency, with a copy to OIRA.

(d) Regulatory Working Group. Within 30 days of the date

of this Executive order, the Administrator of OIRA shall convene a Regulatory Working Group ('Working Group'), which shall consist of representatives of the heads of each agency that the Administrator determines to have significant domestic regulatory responsibility, the Advisors, and the Vice President. The Administrator of OIRA shall chair the Working Group and shall periodically advise the Vice President on the activities of the Working Group. The Working Group shall serve as a forum to assist agencies in identifying and analyzing important regulatory issues including, among others

(1) the development of innovative regulatory techniques,

(2) the methods, efficacy, and utility of comparative risk assessment in regulatory decision-making, and

(3) the development of short forms and other streamlined regulatory approaches for small businesses and other entities). The Working Group shall meet at least quarterly and may meet as a whole or in subgroups of agencies with an interest in particular issues or subject areas. To inform its discussions, the Working Group may commission analytical studies and reports by OIRA, the Administrative Conference of the United States, or any other agency.

(e) Conferences. The Administrator of OIRA shall meet quarterly with representatives of State, local, and tribal governments to identify both existing and proposed regulations that may uniquely or significantly affect those governmental entities. The Administrator of OIRA shall also convene, from time to time, conferences with representatives of businesses, non-governmental organizations, and the public to discuss regulatory issues of common concern.

Section 5. Existing Regulations.

In order to reduce the regulatory burden on the American people, their families, their communities, their State, local, and tribal governments, and their industries; to determine whether regulations promulgated by the executive branch of the federal government have become unjustified or unnecessary as a result of changed circumstances; to confirm that regulations are both compatible with each other and not duplicative or inappropriately burdensome in the aggregate; to ensure that all regulations are consistent with the President's priorities and the principles set forth in this Executive order, within applicable law; and to otherwise improve the effectiveness of existing regulations:

(a) Within 90 days of the date of this Executive order, each agency shall submit to OIRA a program, consistent with its resources and regulatory priorities, under which the agency will periodically review its existing significant regulations to determine whether any such regulations should be modified or eliminated so as to make the agency's regulatory program more effective in achieving the regulatory objectives, less burdensome, or in greater alignment with the President's priorities and the principles set forth in this Executive order. Any significant regulations selected for review shall be included in the agency's annual Plan. The agency shall also identify any legislative mandates that require the agency to promulgate or continue to impose regulations that the agency believes are unnecessary or outdated by reason of changed circumstances.

(b) The Administrator of OIRA shall work with the Regulatory Working Group and other interested entities to pursue the objectives of this section. State, local, and tribal governments are specifically encouraged to assist in the identification of regulations that impose significant or unique burdens on those governmental entities and that appear to have outlived their justification or be otherwise inconsistent with the public interest.

(c) The Vice President, in consultation with the Advisors, may identify for review by the appropriate agency or agencies other existing regulations of an agency or groups of regulations of more than one agency that affect a particular group, industry, or sector of the economy, or may identify legislative mandates that may be appropriate for reconsideration by the Congress.

Section. 6. Centralized Review of Regulations.

The guidelines set forth below shall apply to all regulatory actions, for both new and existing regulations, by agencies other than those agencies specifically exempted by the Administrator of OIRA:

(a) Agency Responsibilities.

> (1) Each agency shall (consistent with its own rules, regulations, or procedures) provide the public with meaningful participation in the regulatory process. In particular, before issuing a notice of proposed rulemaking, each agency should, where appropriate, seek the involvement of those who are intended to benefit from and those expected to be burdened by any regulation (including, specifically, State, local, and tribal officials). In addition, each agency should afford the public a meaningful opportunity to comment on any proposed regulation, which in most cases should include a comment period of not less than 60 days. Each agency also is directed to explore and, where appropriate, use consensual mechanisms for developing regulations, including negotiated rulemaking.
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> (2) Within 60 days of the date of this Executive order, each agency head shall designate a Regulatory Policy Officer who shall report to the agency head. The Regulatory Policy Officer shall be involved at each stage of the regulatory process to foster the development of effective, innovative, and least burdensome regulations and to further the principles set forth in this Executive order.
>
> (3) In addition to adhering to its own rules and procedures and to the requirements of the Administrative Procedure Act, the Regulatory Flexibility Act, the Paperwork Reduction Act, and other applicable law, each agency shall develop its regulatory actions in a timely fashion and adhere to the following procedures with respect to a regulatory action:
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> > (A) Each agency shall provide OIRA, at such times and in the manner specified by the Administrator of OIRA, with a list of its planned regulatory actions, indicating those which the agency believes are significant regulatory actions within the meaning of this Executive order. Absent a material change in the development of the planned regulatory action, those not designated as significant will not be subject to review under this section unless, within 10 working days of receipt of

the list, the Administrator of OIRA notifies the agency that OIRA has determined that a planned regulation is a significant regulatory action within the meaning of this Executive order. The Administrator of OIRA may waive review of any planned regulatory action designated by the agency as significant, in which case the agency need not further comply with subsection (a)(3)(B) or subsection (a)(3)(C) of this section.

(B) For each matter identified as, or determined by the Administrator of OIRA to be, a significant regulatory action, the issuing agency shall provide to OIRA:

(i) The text of the draft regulatory action, together with a reasonably detailed description of the need for the regulatory action and an explanation of how the regulatory action will meet that need; and

(ii) An assessment of the potential costs and benefits of the regulatory action, including an explanation of the manner in which the regulatory action is consistent with a statutory mandate and, to the extent permitted by law, promotes the President's priorities and avoids undue interference with State, local, and tribal governments in the exercise of their governmental functions.

(C) For those matters identified as, or determined by the Administrator of OIRA to be, a significant regulatory action within the scope of section 3(f)(1), the agency shall also provide to OIRA the following additional information developed as part of the agency's decision-making process (unless prohibited by law):

(i) An assessment, including the underlying analysis, of benefits anticipated from the regulatory action (such as, but not limited to, the promotion of the efficient functioning of the economy and private markets, the enhancement of health and safety, the protection of the natural environment, and the elimination or reduction of discrimination or bias) together with, to the extent feasible, a quantification of those benefits;

(ii) An assessment, including the underlying analysis, of costs anticipated from the regulatory action (such as, but not limited to, the direct cost both to the government in administering the regulation and to businesses and others in complying with the regulation, and any adverse effects on the efficient functioning of the economy, private markets (including productivity, employment, and competitiveness), health, safety, and the natural environment), together with, to the extent feasible, a quantification of those costs; and

(iii) An assessment, including the underlying analysis, of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation, identified by the agencies or the public (including improving the current regulation and reasonably viable nonregulatory actions), and an explanation why the planned regulatory action is preferable to the identified potential alternatives.

(D) In emergency situations or when an agency is obligated by law to act more quickly than normal review procedures allow, the agency shall notify OIRA as soon as possible and, to the extent practicable, comply with subsections (a)(3)(B) and (C) of this section. For those regulatory actions that are governed by a statutory or court-imposed deadline, the agency shall, to the extent practicable, schedule rulemaking proceedings so as to permit sufficient time for OIRA to conduct its review, as set forth below in subsection (b)(2) through (4) of this section.

(E) After the regulatory action has been published in the *Federal Register* or otherwise issued to the public, the agency shall:

(i) Make available to the public the information set forth in subsections (a)(3)(B) and (C);

(ii) Identify for the public, in a complete, clear, and simple manner, the substantive changes between the draft submitted to OIRA for review and the action subsequently announced; and

(iii) Identify for the public those changes in the regulatory action that were made at the suggestion or recommendation of OIRA.

(F) All information provided to the public by the agency shall be in plain, understandable language.

(b) OIRA Responsibilities. The Administrator of OIRA shall provide meaningful guidance and oversight so that each agency's regulatory actions are consistent with applicable law, the President's priorities, and the principles set forth in this Executive order and do not conflict with the policies or actions of another agency. OIRA shall, to the extent permitted by law, adhere to the following guidelines:

(1) OIRA may review only actions identified by the agency or by OIRA as significant regulatory actions under subsection (a)(3)(A) of this section.

(2) OIRA shall waive review or notify the agency in writing of the results of its review within the following time periods:

(A) For any notices of inquiry, advance notices of proposed rulemaking, or other preliminary regulatory actions prior to a Notice of Proposed Rulemaking, within 10 working days after the date of submission of the draft action to OIRA;

(B) For all other regulatory actions, within 90 calendar days after the date of submission of the information set forth in subsections (a)(3)(B) and (C) of this section, unless OIRA has previously reviewed this information and, since that review, there has been no material change in the facts and circumstances upon which the regulatory action is based, in which case, OIRA shall complete its review within 45 days; and

(C) The review process may be extended (1) once by no more than 30 calendar days upon the written approval of the Director and (2) at the request of the agency head.

(3) For each regulatory action that the Administrator of OIRA returns to an agency for further consideration of some or all of its provisions, the Administrator of OIRA shall provide the issuing agency a written explanation for such return, setting forth the pertinent provision of this Executive order on which OIRA is relying. If the agency head disagrees with some or all of the bases for the return, the agency head shall so inform the Administrator of OIRA in writing.

(4) Except as otherwise provided by law or required by a Court, in order to ensure greater openness, accessibility, and accountability in the regulatory review process, OIRA shall be governed by the following disclosure requirements:

(A) Only the Administrator of OIRA (or a particular designee) shall receive oral communications initiated by persons not employed by the executive branch of the federal government regarding the substance of a regulatory action under OIRA review;

(B) All substantive communications between OIRA personnel and persons not employed by the executive branch of the federal government regarding a regulatory action under review shall be governed by the following guidelines:

(i) A representative from the issuing agency shall be invited to any meeting between OIRA personnel and such person(s);

(ii) OIRA shall forward to the issuing agency, within 10 working days of receipt of the communication(s), all written communications, regardless of format, between OIRA personnel and any person who is not employed by the executive branch of the federal government, and the dates and names of individuals involved in all substantive oral communications (including meetings to which an agency representative was invited, but did not attend, and telephone conversations between OIRA personnel and any such persons); and

(iii) OIRA shall publicly disclose relevant information about such communication(s), as set forth below in subsection (b)(4)(C) of this section.

(C) OIRA shall maintain a publicly available log that shall contain, at a minimum, the following information pertinent to regulatory actions under review:

(i) The status of all regulatory actions, including if (and if so, when and by whom) Vice Presidential and Presidential consideration was requested;

(ii) A notation of all written communications forwarded to an issuing agency under subsection (b)(4)(B)(ii) of this section; and

(iii) The dates and names of individuals involved in all substantive oral communications, including meetings and telephone conversations, between OIRA personnel and any person not employed by the executive branch of the federal government, and the subject matter discussed during such communications.

(D) After the regulatory action has been published in the *Federal Register* or otherwise issued to the public, or after the agency has announced its decision not to publish or issue the regulatory action, OIRA shall make available to the public all documents exchanged between OIRA and the agency during the review by OIRA under this section.

(5) All information provided to the public by OIRA shall be in plain, understandable language.

Section 7. Resolution of Conflicts.

To the extent permitted by law, disagreements or conflicts between or among agency heads or between OMB and any agency that cannot be resolved by the Administrator of OIRA shall be resolved by the President, or by the Vice President acting at the request of the President, with the relevant agency head (and, as appropriate, other interested government officials). Vice Presidential and Presidential consideration of such disagreements may be initiated only by the Director, by the head of the issuing agency, or by the head of an agency that has a significant interest in the regulatory action at issue. Such review will not be undertaken at the request of other persons, entities, or their agents. Resolution of such conflicts shall be informed by recommendations developed by the Vice President, after consultation with the Advisors (and other executive branch officials or personnel whose responsibilities to the President include the subject matter at issue). The development of these recommendations shall be concluded within 60 days after review has been requested. During the Vice Presidential and Presidential review period, communications with any person not employed by the federal government relating to the substance of the regulatory action under review and directed to the Advisors or their staffs or to the staff of the Vice President shall be in writing and shall be forwarded by the recipient to the affected agency or agencies for inclusion in the public dockets. When the communication is not in writing, such Advisors or staff members shall inform the outside party that the matter is under review and that any comments should be submitted in writing.

At the end of this review process, the President, or the Vice President acting at the request of the President, shall notify the affected agency and the Administrator of OIRA of the President's decision with respect to the matter.

Section. 8. Publication.

Except to the extent required by law, an agency shall not publish in the *Federal Register* or otherwise issue to the public any regulatory action that is subject to review under Section 6 of this Executive order until (1) the Administrator of OIRA notifies the agency that OIRA has waived its review of the action or has completed its review without any requests for further consideration, or (2) the applicable time period in section 6(b)(2) expires without OIRA having notified the agency that it is returning the regulatory action for further consideration under section 6(b)(3), whichever occurs first. If the terms of the preceding sentence have not been satisfied and an agency wants to publish or otherwise issue a regulatory action, the head of that agency may request Presidential consideration through the Vice President, as provided under section 7 of this order. Upon receipt of this request, the Vice President shall notify OIRA and the Advisors. The guidelines and time period set forth in section 7 shall apply to the publication of regulatory actions for which Presidential consideration has been sought.

Section 9. Agency Authority.

Nothing in this order shall be construed as displacing the agencies' authority or responsibilities, as authorized by law.

Section 10. Judicial Review.

Nothing in this Executive order shall affect any otherwise available judicial review of agency action. This Executive order is intended only to improve the internal management of the federal government and does not create any right or benefit, substantive or procedural, enforceable at law or equity by a party against the United States, its agencies or instrumentalities, its officers or employees, or any other person.

Section 11. Revocations.

Executive Orders Nos. 12291 and 12498; all amendments to those Executive orders; all guidelines issued under those orders; and any exemptions from those orders heretofore granted for any category of rule are revoked.